BC GAS INC. 1998 Annual Report

focused *energy*

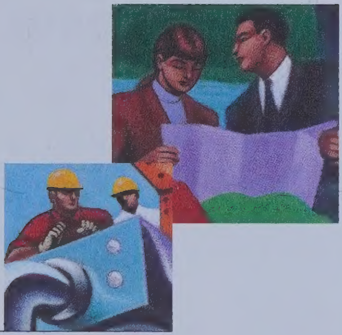
Natural gas distribution

Petroleum transportation

Energy and utility services

Corporate Profile

BC Gas Inc. is a leading provider of energy and utility services in British Columbia. BC Gas Utility is the largest distributor of natural gas in British Columbia, serving 742,000 customers in more than 100 communities. Trans Mountain Pipe Line owns and operates the only pipeline transporting crude oil and refined petroleum products from Alberta to British Columbia and Washington State. The Company also owns a number of non regulated companies involved in energy and utility services. Common shares of BC Gas Inc. are traded on the Toronto, Montreal and Vancouver stock exchanges under the symbol BCG. The Company's head office is in Vancouver, British Columbia.



The transformation of the energy and utility services industry across North America is creating a host of new opportunities. At BC Gas, we're building on our strengths in natural gas distribution and petroleum transportation to achieve success in our chosen markets.

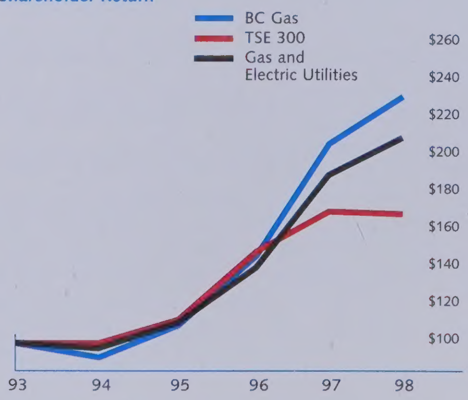
We made major strides forward in 1998 with the development of a focused strategic framework. This will enable the Company to continue to deliver superior value to our customers in an increasingly competitive environment, so that when given the choice, they will choose to remain our customers. Their positive experience with us will serve as our foundation for future growth as we expand our range of products and services. Recognition of the superior value we provide in our current markets will be our springboard for developing new markets.

Our success will be measured by the creation of value for our shareholders, which in turn will create value for our employees and the communities we serve.

Financial Highlights

Years ended December 31	1998	1997	1996
(Dollar amounts in millions except per share data)			
Gross revenues	$ 925.0	$ 933.9	$ 901.4
Net earnings before non-recurring items	$ 71.2	$ 65.2	$ 61.6
Net earnings	$ 71.2	$ 50.8	$ 105.6
Total assets	$ 2,466.1	$ 2,388.1	$ 2,427.1
Earnings per share before non-recurring items	$ 1.85	$ 1.63	$ 1.48
Earnings per share	$ 1.85	$ 1.27	$ 2.53
Dividends per share	$ 1.090	$ 0.975	$ 0.900
Book value per share	$ 15.42	$ 15.05	$ 15.28
Return on equity	12.1%	10.7%	10.3%

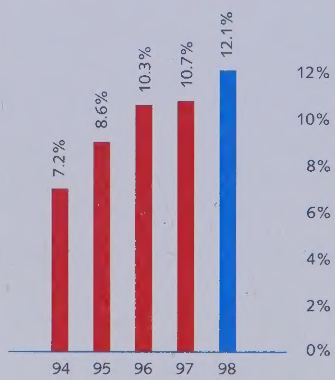
Shareholder Return



Return on an investment of $100 assuming reinvestment of dividends

With reinvested dividends, the total return for BC Gas shareholders in 1998 was 13.8 per cent. This compares with -1.6 per cent for the TSE 300 and 9.6 per cent for the gas and electric utilities index on The Toronto Stock Exchange.

Return On Equity



Our goal is to deliver an annual return on equity of 12 per cent.

Letter to Shareholders

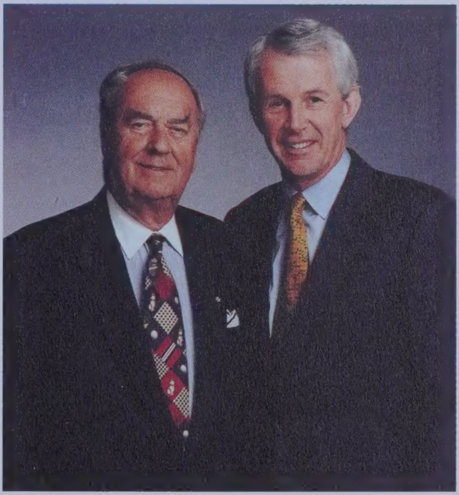
1998 was a year of solid accomplishment across all areas of our business activities.

Strong operating results across each of our business units contributed to a 13.5 per cent increase in earnings per share before non-recurring items. Major development projects now in the planning stage will increase the Company's asset base by one third if approved. In addition, we refined and revitalized our strategic direction to position the Company for further growth opportunities.

In our regulated gas distribution utility, we are refocusing the way we deliver products and services. During the first year of a three-year incentive based regulatory settlement, we realized operating efficiencies that reduced costs to our customers and improved returns to our shareholders. At the same time, we restructured our service delivery systems to meet the competitive realities of an unbundled service environment.

The accomplishments did not come without their costs. We have reduced our workforce in the natural gas utility by approximately 10 per cent and a number of employees have been repositioned throughout the Company.

One challenge to our future earnings growth targets is a lower allowed return on utility equity. In 1998 the allowed return on utility rate base was lowered from 10.25 per cent to 10 per cent and it has been further lowered for 1999 to 9.25 per cent. A lower allowed return, combined with productivity expectations built into our incentive agreement, will raise the performance bar for utility management. We remain committed to our goal of delivering an overall annual return on equity of 12 per cent.



Ronald L. Cliff, Chairman (left)
John M. Reid, President and Chief Executive Officer

BUSINESS DEVELOPMENT

In 1998 Trans Mountain Pipe Line Company Ltd. completed the third year of a five-year incentive based settlement with shippers. Earnings from Trans Mountain were up 12.2 per cent, reflecting higher throughput on the Canadian and U.S. pipeline systems. In July the Company entered into an agreement with Shell Canada Limited and The Broken Hill Proprietary Company Limited to join a

detailed feasibility study for the $440 million Corridor Pipeline. Evaluation of the overall oil sands project is to be completed by third quarter 1999 and, if approved, the Company will build, own and operate 495-km dual pipelines from a proposed Athabasca Oil Sands mine to a pipeline terminal and refinery at Edmonton. We are excited about this project which, if it proceeds, could double our petroleum transportation asset base.

Our second proposed capital project, the Southern Crossing Pipeline Project, is taking longer to become a reality than we had hoped. In April 1998 we were disappointed by the decision from the British Columbia Utilities Commission that denied our application as submitted. However, the Commission encouraged us to negotiate with BC Hydro to enter into agreements whereby BC Gas would supply BC Hydro with gas transportation capacity on the Southern Crossing Pipeline.

We believe the package we put before the Utilities Commission in December 1998 represents the best combination of costs and benefits for consumers of both natural gas and electricity in an increasingly volatile and competitive gas supply environment. We were encouraged by strong support from our customers in submissions filed with the Commission arguing that swift approval of our project is in their best interests. A decision on Southern Crossing is expected in the spring of 1999.

In activities outside our regulated natural gas distribution and petroleum transportation businesses, we continue to seek opportunities to lever our core competencies into new opportunities and to develop opportunities to do new business with existing customers.

In 1998 BC Gas International (BCGI) undertook a significant engineering, procurement and construction project for the first natural gas distribution system in the United Arab Emirates. As a partner in this $46 million project BCGI is responsible for building a utility to serve 25,000 customers in the City of Sharjah in conjunction with a local construction company. This is an opportunity to use our core competencies beyond our traditional distribution area.

Closer to home DESCO (Distributed Energy Services Company) completed its first year of providing utility services to Sun Peaks Resort. These services include propane supply, storage, distribution, and system operation and expansion. Other services provided to the resort community include billing services, consulting and related services with the possibility of water and sewer services to be added. DESCO is establishing an attractive

niche business providing a range of utility services to municipalities and resort communities. In the coming year we expect that DESCO will take a much more active role in the provision of services related to water delivery and treatment systems.

Home*works*® in 1998 took a step forward with our other key strategy of selling more products to existing customers with the launch of HEAT*Pro*®. Introduced in the Greater Vancouver market in September 1998, HEAT*Pro*® provides a convenient heating service package that will over time be expanded to include home heating replacement, installation, and regular maintenance. HEAT*Pro*® is conducted through a network of contractors, including BC Gas employees.

NEW TECHNOLOGY

Revitalizing ourselves for a customer focused, competitive environment demands significant change and improvement in the support services and information technology of the Company. On the Labour Day weekend our Prince George branch went 'live' with a pilot customer information system for 28,000 customers in the area. The pilot has been delivering on all its promises and with its enriched suite of services available, is now drawing serious attention from potential municipal customers. In addition, throughout 1998 a dedicated team of BC Gas employees working with a team of outside consultants analyzed and reworked our systems related to finance, human resources and materials management in preparation for the installation of a SAP enterprise management system with the potential for great productivity gains. The system was turned on in January 1999 and the early indications are that, after getting over the bumps that result from any major change, the combination of software and business process renewal will deliver the productivity gains we require.

FINANCIAL PERFORMANCE

For 1998 earnings per share before non-recurring items were $1.85, up 13.5 per cent from $1.63 in 1997. The increase before non-recurring items results from a combination of improved earnings—$71.2 million, up from $65.2 million in 1997—and a reduction in the average number of shares outstanding as a result of the Company's share repurchase program. Including non-recurring items, the earnings were $71.2 million in 1998 compared to $50.8 in 1997, resulting in earnings per share in 1998 of $1.85, up from $1.27 in 1997.

Earnings improvements were delivered by all major units of the Company. Earnings for natural gas distribution were up by $1.6 million as a result of productivity improvements implemented in the restructuring program at BC Gas Utility in early 1998. The gains from

Net Earnings (Loss)

(in millions of dollars except per share amounts)

Years ended December 31	1998		1997	
	$	Per Share	$	Per Share
Natural gas distribution	$ 51.8	$ 1.35	$ 50.2	$ 1.25
Petroleum transportation	22.9	0.59	20.4	0.51
Other activities	(3.5)	(0.09)	(5.4)	(0.13)
Earnings before non-recurring items	71.2	1.85	65.2	1.63
Non-recurring items	–	–	(14.4)	(0.36)
Net earnings	$71.2	$ 1.85	$ 50.8	$ 1.27

productivity improvements were partially offset by a reduction in the authorized return on common equity from 10.25 per cent in 1997 to 10.0 per cent in 1998.

Petroleum transportation earnings for the year increased by $2.5 million over 1997 due to increased throughput on both the Canadian and U.S. portions of the pipeline.

Included in other activities are non-regulated energy and utility services as well as corporate interest and administration charges. Earnings flowing from the construction of a water treatment facility in Dartmouth, Nova Scotia and a natural gas distribution system in the City of Sharjah were offset by higher interest expense associated with borrowings to support the Company's share repurchase program. The result is a $1.9 million reduction in the net loss from this segment compared to 1997.

In 1998 your Company substantially completed the share repurchase program initiated in August 1996. During this period, the Company repurchased 3.9 million common shares, representing 8.4 per cent of shares outstanding. We will continue to undertake initiatives to optimize the Company's capital structure, maintaining a strong financial base from which we can pursue attractive growth opportunities.

Strategic Direction

The BC Gas Group of Companies is dedicated to becoming a leading supplier of energy and utility services in an increasingly competitive environment. Over the past year, we put in place a new strategic framework that builds on our strengths and core capabilities and provides a framework for ongoing growth and success.

Our core businesses are committed to providing such superior value to our customers that, given the choice, they will choose to remain our customers. This reflects our first strategic goal: Secure and optimize our base business and franchise, and expand the system for customer benefit.

The recognition of superior value we provide in our current markets will be the springboard from which we develop new markets for our critical core competencies. Our second strategic goal: Grow from core business to new multi-utility markets.

The positive experience customers have from dealing with us will form the base for future growth as we expand our range of products and services. Our third strategic goal: Position BC Gas to sell new products and services to our existing customers.

We intend to become the dominant provider of multi-utility services in the Pacific Northwest.

To reflect higher ongoing earnings for the Company, in April the directors announced a 12 per cent increase in the quarterly dividend on common shares, to 28 cents per share.

1998 was the fourth consecutive year in which the total return for BC Gas shareholders exceeded the total returns on both the TSE 300 index and the gas and electric utilities subindex. Despite lower returns for the broader stock markets, BC Gas shares provided a total return of 13.8 per cent to shareholders in 1998.

YEAR 2000

We have undertaken a rigorous, company-wide program to assess the potential impact of the Year 2000 issue. Where necessary, system upgrades and conversions are underway and we expect complete remediation and testing of all business critical systems by June 30, 1999. While we have a very high level of confidence in our systems, it is not possible, given the nature of the risks associated with the Year 2000 issue, to be certain that all aspects of the issue will be fully resolved—particularly aspects related to systems attached to, or operated by customers, suppliers, and other third parties. Accordingly, the Company is developing contingency plans to deal with failures that could impact our essential services and core operations as a result of the Year 2000 issue.

STRATEGIC DIRECTION

In the fall of 1998 management put before your directors a comprehensive strategic direction document. It has subsequently been rolled out to employees of the Company.

To that end management has determined that the BC Gas Group of Companies is dedicated to becoming a leading supplier of energy and utility services in an increasingly competitive market driven environment. The focus of the strategic plan has been kept tight—three straightforward, customer-focused goals around which a number of strategies and dozens of action plans have been grouped. Our success will be measured by the creation of value for our shareholders which in turn will create value for our employees and the communities we serve. Our success will be achieved by our employees and their commitment to excellence.

ACKNOWLEDGEMENTS

We are pleased to welcome Mr. Mark Cullen to the board of directors. Mr. Cullen enjoyed a lengthy career as a senior investment banker to British Columbia based companies and recently retired as Vice Chairman and Director of RBC Dominion Securities Inc.

Mr. Frank Murphy will retire from the board of directors at the annual meeting in April. We have appreciated his advice and counsel during his time on the board and we wish him well in his retirement.

We also acknowledge the support, commitment and dedication of our employees in a very challenging business environment. Their ongoing support will be instrumental in sustaining our future success.

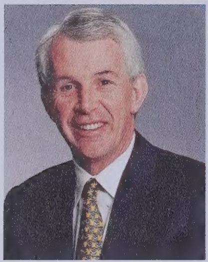
R. Laurence Cliff

Ronald L. Cliff
Chairman

J. M. Reid

John M. Reid
President and Chief Executive Officer

March 9, 1999



John M. Reid, President and Chief Executive Officer

BC Gas' revitalized business strategy is focused on creating shareholder value by delivering superior value for customers. Here, president John Reid addresses approaches to several key issues as the Company drives to become a leading supplier of energy and utility services in an increasingly competitive environment.

Questions and Answers

How does BC Gas measure performance?

Our goal is to achieve an annual return on equity of 12 per cent. For 1998, our return on common equity was 12.1 per cent, up from 10.7 per cent in 1997. Despite a lower allowed return on equity for BC Gas Utility in 1999 and a slower pace of economic growth in British Columbia, we believe our focused strategic direction and solid business base will enable us to achieve this target over time.

How do projects such as the proposed Southern Crossing Pipeline and Corridor Pipeline build on the Company's base business?

Both projects take advantage of our strengths and expertise to generate shareholder value. Southern Crossing utilizes our natural gas expertise to create competition among natural gas suppliers and improve security of supply for BC Gas customers. Corridor Pipeline capitalizes on Trans Mountain's capabilities in building and operating petroleum pipelines, enabling the Company to participate in the further development of Alberta's substantial oil sands deposit.

What is the Company's approach to business development?

Our business development activities are focused on adding value for shareholders by capitalizing on opportunities that take advantage of our core competencies while managing business risk associated with new investments.

How do you plan to deliver superior value to customers?

Customers want increasingly better products and services at a low cost. Our operational excellence program is founded on continuous improvement in key cost, safety and customer satisfaction measures. We are implementing new information systems to enable the Company to respond to new technology and changing customer needs. At the same time, we are working with regulators to extend and enhance incentive regulatory environments.

Why did the Company exit natural gas marketing?

Commodity trading is an increasingly competitive business that doesn't fit our corporate strategy for attractive return within a level of manageable risk. We sold the Canadian energy marketing arm in 1998 and the U.S. energy marketing operation in 1997.

What advances has BC Gas made in non-regulated businesses?

We are gaining increased market presence with new offerings under our retail Home*works*® brand. We're also involved in a number of ventures that use our expertise in utility management to meet the growing demand for more standardized utility services. We believe our non regulated businesses are positioned to realize significant growth over the coming years.

What is your approach to international investment?

BC Gas International is pursuing opportunities in the growing engineering, procurement and construction sector and investigating minor equity participation in natural gas system developments. This is an exciting area for the Company that offers good potential for growth from our core competencies with manageable risk.

What is BC Gas doing to prepare for the multiple utility environment?

We are broadening our non regulated utility service line to provide multiple utilities, including electricity, measurement and water and wastewater treatment as well as natural gas distribution. The evolution of a multiple utility platform will ultimately provide customers with more choice, enabling them to save on how they use energy.

BC Gas is building on its reputation for quality service and reliability to create superior value for customers.

Natural Gas Distribution

At BC Gas Utility, our commitment to a true customer focus is founded on developing a thorough understanding of our customers' needs, rigourous benchmarking of our performance, and disciplined leadership and motivated employees, supported by enabling technology.

The Company launched a central customer care centre in Kelowna in 1998 to provide longer hours of telephone available service to customers throughout the Interior. In the Lower Mainland, a fee for service was introduced for non-emergency heating appliance calls, thereby ensuring that customers who do not call for such services are not required to pay for them through rates. Telephone surveys have been conducted of customers following various types of transactions. Qualitative research, such as focus groups, has been conducted to determine how customers might prefer to do business with us in future.

Change can be effectively implemented only by people who have the personal resources to stay focused on the desired outcomes. We are refining and updating our leadership competencies at BC Gas; we are updating the performance measurement process for management to ensure it links individual performance to business plans; and we are introducing an integrated scorecard for the executive group which includes customer, employee, and growth performance measures as well as financial measures.

As the industry moves from a utility orientation to a market focus, the implementation of a new technology platform at BC Gas Utility will significantly improve the Company's information base and provide the infrastructure for a multi-utility environment. A key component of this infrastructure is a new integrated business information system, implemented in January 1999. The new system supports restructured work processes throughout the Company, contributing to improved decision making and greater

In a residential pilot study conducted in 1998, customers had a choice of ways to access their BC Gas account–including using the Internet. The study is part of a new customer information system being developed to respond faster and more effectively to customer needs.

efficiencies. The new system is also a vital component of the Company's action plan to address the Year 2000 issue.

The Company is continuing to develop a new customer management environment, based on a new Customer Information System (CIS) and call handling technologies, designed to increase efficiency and enable the Company to respond faster and more effectively to customer needs. Two pilot studies were conducted during the year to test new approaches and assess customer response. In the residential pilot study, 28,000 customers in Prince George were given a choice of methods for accessing their accounts and were able to directly enter their meter information, contributing to lower costs and increased accuracy. The second pilot study provided "real time" information for selected industrial customers, enabling them to manipulate their load profile. This is a major advantage when energy is a major part of a customer's cost structure. When fully implemented, this new customer environment will support retail commodity deregulation and sales of the Company's commodity and non-commodity retail offerings.

During the year, BC Gas Utility completed the first phase of a geographical information system (GIS) with development of a central data base of mapping and facilities information. When fully implemented, the new system will be accessible throughout the province and support streamlined business processes, contributing to significant operational efficiencies. The GIS will ultimately link to the Company's new customer information and work management systems, enabling improved service to customers and improved emergency management. In 1999 the Company will develop applications to improve efficiencies associated with corrosion analysis, gas network analysis, leak management, emergency response and valve maintenance.

BC Gas is actively working to ensure that emerging technologies for automated meter reading (AMR) will meet the requirements of the Company and its customers. Providing AMR will allow for frequent collection of meter readings which will offer the opportunity to profile and optimize energy supply, storage and utilization on a continuous basis. Multi-utility synergies are also possible as new technologies are being developed to allow for "real time" reading of electricity, water and gas meters. When eventually implemented, AMR will improve security, safety and efficiency of energy supply and provide customers with greater choice of energy delivery options, allowing them to save on how they use energy.

GAS SUPPLY

The Company has a number of initiatives in place to minimize natural gas supply costs and protect customers from price fluctuations. As a result of new contracts negotiated with major suppliers, the Company is realizing greater flexibility at a reduced cost. Higher market prices for natural gas purchased from producers, however, necessitated a customer rate increase, implemented effective January 1, 1999. The price paid by BC Gas for natural gas is a flow through cost that is directly recoverable from customers.

A program to mitigate the overall cost of natural gas and associated transportation and storage capacity realized benefits of $53 million for the contract year ended October 31, 1998. Approximately $51 million of this amount contributed to lower rates for customers.

In December 1998 BC Gas Utility filed an application with the British Columbia Utilities Commission (BCUC) to construct and operate the Southern Crossing Pipeline. The application includes shipping commitments as well as peaking supply arrangements from BC Hydro and PG&E Energy Trading, Canada Corporation for 105 million cubic feet of natural gas over a 10-year period. When the BCUC denied a previous application in April 1998, it directed BC Gas to secure third party transportation commitments and to examine the feasibility of obtaining peak shaving from BC Hydro and its natural gas-fired electricity suppliers. The Company believes Southern Crossing is the best proposal to meet identified needs of customers. A decision on the new application is expected in the spring of 1999.

BC Gas has also reached agreement with BC Hydro to provide firm transportation service across the Lower Mainland system to serve their gas-fired generation facilities. This agreement will result in an annual demand payment of $9.8 million. To meet the firm obligations, BC Gas will be applying to the BCUC to construct compression facilities in the Fraser Valley at a cost of approximately $40 million.

The proposed Southern Crossing Pipeline would loop BC Gas Utility's existing pipeline to access alternate sources of natural gas.

NATURAL GAS VEHICLES

BC Gas advanced its natural gas vehicles (NGV) program in 1998 with expanded support for high usage fleets and a new partnership with Ford Motor Company. Ford selected Vancouver as one of eight North American cities to market its factory-built natural gas vehicles. Under the partnership,

BC Gas will participate in a significant marketing program. The NGV program builds on the Company's expertise in natural gas compression, improves use of the natural gas infrastructure and promotes air quality in our operating region.

BC Gas is working with the RCMP throughout the province and with BC Transit and others to help them integrate natural gas vehicles into their fleets. During the year, the RCMP took delivery of 40 original equipment manufacture vehicles. Each vehicle is expected to cost an average of $4,000 less per year to operate than a gasoline fueled car while maintaining the same performance level. In 1998 BC Transit doubled its NGV fleet to 50 buses. BC Gas has worked with BC Transit's NGV program since the mid-1980s. BC Gas plans to further expand its NGV activities in keeping with demand.

BC Gas is working with the RCMP in British Columbia to help the force integrate natural gas vehicles into its fleet. BC Gas is a leader in natural gas vehicles, a growing area that contributes to cleaner air and supports better use of the natural gas infrastructure.

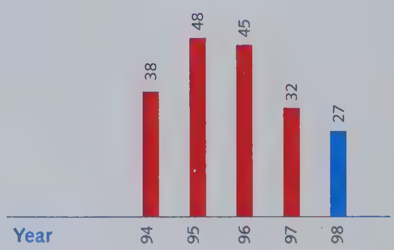
MEASUREMENT

Over the past year, BC Gas Utility's Measurement Technologies department began servicing electric and gas meters for other utilities. This opportunity was enabled by the department achieving ISO 9002 certification and accreditation through Measurement Canada, both of which are quality assurance prerequisites for servicing meters for external clients. A reduction in servicing costs through continuous process improvements was also a significant factor in the viability of providing meter services. The Company and Measurement Technologies plan to expand this business over the coming year.

Following advancements in quality and productivity, BC Gas is now providing meter servicing for a number of external utilities. This is one example of the Company's strategy to grow the core business into new markets.

SAFETY

As a result of the committed efforts of employees throughout the Company, BC Gas Utility recorded improved safety performance. In 1998 lost time injuries were down 15 per cent from the previous year while preventable vehicle accidents declined 27 per cent. The improvements reflect the integration of safety into business processes and clear performance measures which reinforce accountability and expectations throughout the organization.



Safety performance is integral to BC Gas Utility's business success. In 1998 lost time injuries among utility employees were down 29 per cent from four years ago.

ENVIRONMENT

BC Gas Utility is committed to operating in an environmentally responsible manner. In 1998 we completed an external evaluation of the Company's environmental management system relative to the ISO14001 standard and are implementing plans to become ISO compliant. Over the past five years, BC Gas Utility has delivered 6,600 person hours of environmental training, conducted 28 environmental audits of its facilities and issued 26 audit reports. Ninety-three per cent of action items identified in the audit reports are now complete.

The Company continues to be an active participant in Canada's Climate Change Voluntary Challenge and Registry, a program to encourage and track voluntary greenhouse gas emissions reductions in Canada. The Company's 1998 Progress Report, filed with the Registry, was ranked 10th in Canada by an independent organization involved in environmental policy development. Although total emissions from Company operations will increase as the system expands to meet new customer growth, the Company forecasts a 10 per cent reduction in greenhouse gas emissions on a per customer basis between 1990 and 2000.

BC Gas actively supports the health and well-being of the more than 100 communities where it operates. The Company is involved in a wide variety of sponsorships aimed at developing long-term sustainable programs that help people help themselves, are relevant to the Company's business and have value to local communities.

In a youth energy audit, a new initiative sponsored by BC Gas in conjunction with the Sage Foundation, a student reads a light meter while another records the results. The first municipal audit was conducted at Trail City Hall in 1998 and a number are planned for 1999. The audits involve local youth in promoting energy conservation and reducing solid waste.

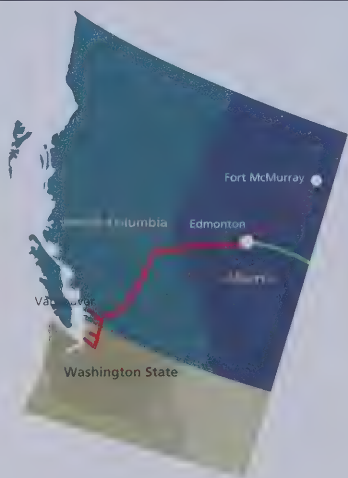
Petroleum Transportation

Trans Mountain enjoyed strong deliveries on its Canadian mainline and U.S. pipeline systems in 1998. In addition, a significant development occurred during the year when the Company joined with Shell Canada Limited to develop the proposed Corridor Pipeline system in northern Alberta.

In July the Company contracted with Shell and The Broken Hill Proprietary Company Limited to carry out a detailed feasibility study for the $440-million Corridor Pipeline. The Corridor pipeline is an integral part of the overall technical and commercial evaluation of Shell's proposed Athabasca Oil Sands Project, which includes a mine at Muskeg River north of Fort McMurray, Alberta and a bitumen-to-synthetic crude oil upgrader at Shell's Scotford refinery at Fort Saskatchewan near Edmonton, Alberta.

The feasibility study will be completed in the third quarter of 1999 and if Shell decides to proceed with the project, the Company will build, own and operate the 495-km dual pipelines from the mine to the upgrader and on to the terminal and refinery hub at Edmonton. A final decision on the project will be made by the fourth quarter 1999 with start-up scheduled for 2002. The main pipeline will transport 215,000 barrels per day of diluted bitumen from the mine extraction plant to an upgrader in Fort Saskatchewan where 65,000 barrels per day of diluent will be recovered and returned north to the mine site. The ongoing connection into the Edmonton hub will permit access to other markets for unprocessed diluted bitumen and upgraded synthetic crude oil. The Corridor Pipeline may also transport diluted bitumen and synthetic crude from other projects as they are developed in the Athabasca region. The pipeline will capitalize on the Company's expertise in building and operating petroleum pipeline systems.

Trans Mountain Pipe Line | Corridor Pipeline (proposed) | Enbridge



If Shell Canada's proposed Athabasca Oil Sands Project proceeds, the Company will build, own and operate the proposed Corridor pipeline from Fort McMurray to Edmonton.

Deliveries in 1998 on Trans Mountain's mainline system from Edmonton to the Vancouver area were up 10 per cent from 1997, reflecting increased shipments of crude oil during the first six months. Mainline

All Trans Mountain employees are participating in training sessions developed to promote a shared understanding of environmental issues and awareness of initiatives resulting from ongoing development of the Company's environmental management system.

deliveries of crude oil and refined products averaged 40,160 cubic metres per day in 1998.

Plans to expand capacity of Trans Mountain's mainline have been delayed as a result of the volatility of crude oil production and markets caused by current low oil prices. The system will be expanded when market conditions improve and additional capacity is required.

The five-year incentive agreement now in place for the Company's Canadian mainline system allows shippers to share in net income above a specified threshold level. The total share of pre-tax revenues from all 1998 incentives that will be credited in 1999 to mainline shippers is $4.8 million. The Company's comparable share of incentive revenues for the same period was $4.0 million. Negotiations for a second five-year incentive toll agreement have commenced.

Delivery volumes on Trans Mountain's U.S. system continue to be strong. In 1998 Trans Mountain delivered approximately 19 per cent of the capacity of the refineries connected to its U.S. system. Because the Company anticipates this market will continue to grow, a $3.6-million (U.S.) meter station at Ferndale will be constructed to facilitate future growth in crude oil deliveries to the TOSCO and ARCO refineries.

Trans Mountain's expertise in petroleum transportation and terminalling is founded on the integration of pipeline integrity, superior safety performance and environmental stewardship into all areas of operation. To further ensure soundness and safety of the system, the Company is hydrostatically retesting the entire pipeline system over a 12-year period.

To control emissions of volatile organic compounds and reduce odour, Trans Mountain is installing a vapour control unit at its Westridge Marine Terminal where tankers are loaded with crude oil for offshore markets. The new facility will be operational by mid-1999.

On a long-term basis, Trans Mountain should continue to benefit from increased demand on the U.S. west coast related to declining production of heavy crude oil in California and conventional crude oil in Alaska. The Company continues to pursue opportunities for growth in crude oil and refined products transportation and terminalling outside its current operating area.

Energy and Utility Services

Energy and utility service opportunities are emerging outside of the regulated utility environment. BC Gas is capitalizing on its utility expertise and the Company's reputation for quality service and reliability to take advantage of these opportunities to pursue these markets both regionally and internationally.

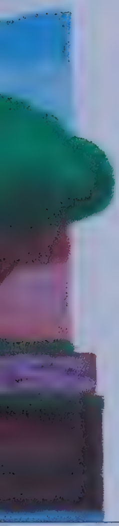
MULTI-UTILITY SERVICES

Since its formation in 1997, DESCO Distributed Energy Services Co. Ltd. has established a position as an active player in the emerging market for energy and utility services. Over the past year, DESCO secured contracts to provide a variety of energy and utility services for a number of municipalities, resorts, institutions and industrial customers. As municipalities and other major customers look to professional service companies to provide specialized services, BC Gas is developing this business with an integrated suite of multi-utility services, including natural gas, water, electricity, customer care and measurement.

A significant accomplishment in 1998 was the completion of a water treatment plant which started serving 100,000 residents of Dartmouth, Nova Scotia in December 1998. The experience gained with this project provides a solid base as the Company pursues other opportunities in the water treatment, water distribution and sewer businesses.

Also in 1998 BC Gas was selected by Kelowna, B.C. and Lethbridge, Alberta to provide integrated utility services for the cities' respective electric utilities. In partnership with other energy and utility companies, BC Gas is providing packages of customized services to meet the needs of these municipal customers.

During 1998 DESCO completed its first full year of deliveries of liquefied natural gas from the BC Gas plant in Delta to a remote satellite storage and vapourizing facility at an industrial site near Salmon Arm. 1998 was also



In the future, one service provider will deliver multiple utilities, including natural gas, water and electricity. Advances in technology will also allow for metering of different commodities through one meter.

DESCO's first full year of providing utility services to Sun Peaks Resort near Kamloops. In addition to meeting the ski resort's needs for propane supply, storage, operation, maintenance and system expansion, DESCO provided billing, consulting and other related services. DESCO is pursuing opportunities to provide integrated utility services for a number of other provincial resorts.

RETAIL ENERGY SERVICES

Over the past year, Home*works*® strengthened its market presence as an active player in the evolving retail market for home comfort packages. HEAT*Pro*® was introduced in September to provide residents in Greater Vancouver with a convenient heating service from a trusted provider. The heating package, which will be developed over time to include home heating replacement, installation and regular maintenance, provides Home*works*® with a large base of customer contacts for its other retail offerings. HEAT*Pro*® is conducted through a network of contractors, including BC Gas employees.

Recent market research conducted among customers of Home*works*® energy-based renovation program indicated high potential for repeat business. Introduced in 1997, the renovation program allows homeowners to increase home comfort through renovations that promote energy efficiency, while offering quality assurance on every completed job. The program is conducted through a province-wide network of trained contractors.

In 1998 Home*works*® launched HEAT*Pro*®, providing homeowners with another service building on the Company's reputation for trust, security and home comfort. The heating package will be developed over time to include home heating replacement, installation and regular maintenance.

BC Gas International is building a natural gas distribution system in the City of Sharjah in the United Arab Emirates.

INTERNATIONAL

BC Gas International (BCGI) broadened the scope of its business in 1998 with a $46-million Engineering, Procurement and Construction (EPC) project for the first natural gas distribution system in the United Arab Emirates. As partner in the project, BCGI is responsible for building a utility to serve 25,000 customers in the City of Sharjah in conjunction with a local construction company. The project is the first of a four-phase development that will ultimately connect natural gas supply to all residential areas of the city as well as commercial and industrial customers. Phase one is scheduled for completion in mid-2000.

In addition to pursuing other contracts in the growing EPC sector, BCGI is selectively evaluating projects that require financing or modest equity investments. The Company is solidifying strategic alliances with major Canadian and international energy companies to increase access to global opportunities and provide clients with a comprehensive package of services. The Company continues to provide consulting and training services for utilities in eastern Europe as an entrée to new business.

BCGI builds on the Company's core competencies in engineering design, project management, construction supervision and gas system operation. In addition to taking advantage of business opportunities in the development of natural gas systems, BCGI's international involvement enables BC Gas employees to gain valuable knowledge and expertise.

The Company is well positioned to expand its business to include multi-utility services and other related businesses.

Financial Review

MANAGEMENT DISCUSSION AND ANALYSIS

This discussion and analysis is a review of the operating results, business risks, financial condition and outlook for BC Gas Inc. ("BC Gas" or the "Company"). This discussion should be read in conjunction with the consolidated financial statements of the Company and related notes.

OVERVIEW

BC Gas is a leading provider of energy and utility services in British Columbia through its two principal operating subsidiaries, BC Gas Utility Ltd. ("BC Gas Utility" or the "Utility") and Trans Mountain Pipe Line Company Ltd. ("Trans Mountain"), and through a number of non-regulated businesses. BC Gas Utility and Trans Mountain together comprise more than 90% of the assets of the Company.

BUSINESS SEGMENTS OF BC GAS

Natural Gas Distribution

The Company's natural gas distribution operations consist primarily of BC Gas Utility and several small related utility operations. BC Gas Utility is the largest gas distribution utility in British Columbia serving approximately 90% of the province's natural gas users in approximately 100 communities. BC Gas Utility provides transmission and distribution services to its customers, and obtains gas supplies primarily on behalf of residential and commercial customers, making the Utility the largest single buyer of natural gas in B.C. Major areas served are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of the province.

Petroleum Transportation

BC Gas' petroleum transportation operations are carried out by Trans Mountain, which owns and operates a pipeline system transporting crude oil and refined products from Edmonton, Alberta to Burnaby, B.C. The pipeline of a U.S. subsidiary delivers Canadian crude oil to several refineries in Washington State. In addition, Trans Mountain owns and operates a marine terminal in the Port of Vancouver and a jet fuel pipeline to a storage system at Vancouver International Airport.

Other Activities

BC Gas has other activities which include non-regulated energy and utility services as well as corporate interest and administration charges. The non-regulated services include independent power production, international consulting, development of water related infrastructure projects and retail energy services. These businesses are either owned by the Company's subsidiary, Inland Pacific Enterprises Ltd. ("IPEL"), or held directly by BC Gas.

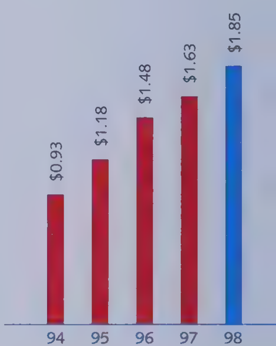
The contribution to earnings per share of each segment is as follows:

Years ended December 31	1998	1997
Natural gas distribution	$ 1.35	$ 1.25
Petroleum transportation	0.59	0.51
Other activities	(0.09)	(0.13)
	1.85	1.63
Non-recurring items	–	(0.36)
Earnings per common share	$ 1.85	$ 1.27

Non-recurring losses of $14.4 million or $0.36 per share for the year ended December 31, 1997 were comprised of costs of $13.7 million ($9.3 million or $0.23 per share after tax) the Company incurred in anticipation of the disposition of its interest in NW Energy (Williams Lake) Limited Partnership ("NW Energy"), and a provision of $9.4 million ($5.1 million or $0.13 per share after tax) for costs relating to a restructuring program at BC Gas Utility.

BC Gas Inc.

Earnings Per Share Before Non-Recurring Items



On a per share basis, 1998 earnings before non-recurring items were $1.85, up from $1.63 in 1997. The increase reflects improved earnings and a reduction in the average num of common shares outstanding, resulting from the Company's share repurchase program.

MANAGEMENT DISCUSSION AND ANALYSIS

Natural Gas Distribution Earnings Before Restructuring Costs, Income Taxes and Non-Controlling Interest ($ millions)

Earnings from natural gas distribution were higher in 1998 as a result of productivity improvements.

EARNINGS PERFORMANCE

Earnings before non-recurring items were 9.2% higher in 1998 than in 1997. Net earnings before non-recurring items were $71.2 million in 1998 versus $65.2 million in 1997. On a per share basis, net earnings before non-recurring items were $1.85 per common share in 1998 compared with $1.63 in 1997. An analysis of the increase in earnings is as follows:

In millions of dollars	
Net earnings 1997	$50.8
1997 Non-recurring items:	
NW Energy disposition costs	9.3
BC Gas Utility restructuring costs	5.1
Continuing earnings 1997	65.2
Natural Gas Distribution:	
Lower allowed return on common equity in 1998	(1.3)
Productivity improvements and other items	2.9
Petroleum Transportation:	
Higher throughput and other items	2.5
Other Activities:	
Higher revenues, offset in part by higher corporate interest expense	1.9
Net earnings 1998	$71.2

NATURAL GAS DISTRIBUTION

Contribution to Earnings

In millions of dollars	1998	1997
Gross revenues	$742.4	$765.8
Operating expenses		
Cost of natural gas	338.2	375.3
Operations and maintenance	116.9	120.8
Depreciation and amortization	61.4	55.4
Property and other taxes	31.5	30.9
	548.0	582.4
Operating income	194.4	183.4
Financing costs	86.8	84.0
Earnings before restructuring costs, income taxes and non-controlling interest	$107.6	$ 99.4

Revenues

Revenues from natural gas distribution decreased to $742.4 million during 1998 from $765.8 million in 1997. Revenues are set to recover the Utility's cost of service, the largest component of which is the cost of natural gas. In 1998, revenues were lower primarily as a result of reductions in the cost of natural gas, which is flowed through into customer rates.

During 1998, 9,989 new customers were added, bringing the total number of gas utility customers to 742,305 at year end. This growth in customers was mainly in the heating market for new single-family houses where natural gas continues to achieve a very high market share.

Industrial sales service increased by 106 terajoules while transportation volumes increased by 164 terajoules from the previous year. The Utility earns approximately the same margin regardless of whether a customer contracts for sales or transportation service.

BC Gas Utility has a number of firm and interruptible contracts with the British Columbia Hydro and Power Authority ("BC Hydro") Burrard Thermal Plant near Vancouver. The margin from these contracts in 1998 was $0.3 million, a decrease of $0.7 million from 1997. In addition to these contracts, there was a $5.0 million per annum minimum fixed price contract which expired in September 1998. The revenue from this contract is included in other operating revenue.

To replace these BC Hydro contracts, BC Gas has reached agreement with BC Hydro for firm transportation services to serve BC Hydro's gas fired generation facilities. This agreement, currently under review by the British Columbia Utilities Commission (the "BCUC"), will provide annual transportation revenue of $9.8 million per year, after completion of compression facilities in the Lower Mainland to meet BC Hydro's requirements. Under the new agreement, there are no long-term commitments for the supply of gas. Agreement has also been reached regarding BC Hydro's participation in the Southern Crossing Pipeline ("SCP") project and to provide peaking gas supply which form part of a revised SCP application, as discussed below under "Regulation and Rates."

MANAGEMENT DISCUSSION AND ANALYSIS

Expenses

Expenses for the natural gas distribution segment of the Company include the cost of natural gas, operations and maintenance expenses, depreciation and amortization, and property and other taxes. Total operating expenses were $548.0 million in 1998 compared with $582.4 million in 1997.

Cost of natural gas amounted to $338.2 million in 1998 compared with $375.3 million in 1997. The decrease in cost of gas reflects a decrease in the expected price of natural gas bought by the Utility on behalf of its customers and a reduction in the volumes sold due to warmer weather.

Operations and maintenance expenses decreased to $116.9 million in 1998 from $120.8 million in 1997. This decrease was due largely to productivity improvements flowing from a significant restructuring program at BC Gas Utility which was implemented in early 1998.

Increased investment in gas plant in service and increased amortization of deferred charges resulted in depreciation and amortization expense rising to $61.4 million in 1998 from $55.4 million in 1997.

Growth in the asset base of the Company, in conjunction with higher tax rates, resulted in property and other taxes increasing by $0.6 million to $31.5 million in 1998.

Financing costs increased to $86.8 million in 1998 from $84.0 million in the previous year largely as a result of higher debt balances and higher short-term interest rates during the year.

Regulation and Rates – BC Gas Utility

BC Gas Utility is regulated by the British Columbia Utilities Commission, which approves rates and tolls for services and the construction of facilities. Traditionally, rates have been set through historical cost rate base and rate of return methodology. Since 1996, incentive rate methodologies have been approved and implemented by the BCUC as part of the rate setting process in order to enhance both value to customers and returns to shareholders.

A number of regulatory deferral accounts are in place to manage the Utility's exposure to certain risks. The three most significant deferral accounts relate to the risks of weather, cost of natural gas, and interest rates.

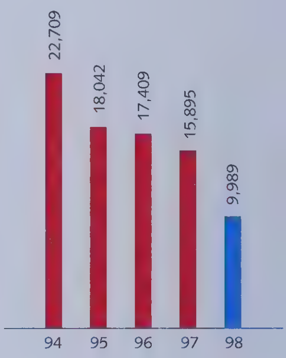
The deferral accounts for weather and cost of natural gas reduce the Utility's earnings exposure to these risks by deferring any variances between projected and actual gas consumption and gas costs, and refunding or recovering those variances in future customer rates. Transportation and sales services to industrial customers are not covered by these deferral accounts. As a result of these deferral accounts, variations in reported revenues are caused mainly by changes in gas costs and other components of the Utility's cost of service which are recovered in customer rates. Changes in volumes of gas sold to core market customers due to weather or other factors have a less significant impact on reported revenues.

BC Gas Utility also has in place short-term and long-term interest deferral accounts to absorb interest rate fluctuations. The Utility's interest deferral accounts effectively locked in the cost of short-term funds attributable to regulated assets during 1998 at 5.0%, compared with 4.0% during 1997.

Allowed Return on Equity

The Utility's 1998 allowed ROE of 10.0% was determined based on a formula that applied a risk premium to a forecast of long-term Government of Canada bond yields. The decline from 10.25% in 1997 was a result of a forecast decline in long-term bond yields. For 1999, the Utility's allowed ROE has been set at 9.25% using the same formula, reflecting a continued decline in forecasted long-term bond yields.

Natural Gas Distribution Customer Additions



Since 1993, BC Gas Utility's customer base has increased 12.8 per cent to 742,305.

MANAGEMENT DISCUSSION AND ANALYSIS

The table below contains historical information on rate base, allowed ROE and the common equity component used in setting rates for the Utility:

		Common Equity	
	Mid-year Rate Base (in millions)	Allowed Return	Equity Component
1998	$1,557.8[1]	10.00%	33%
1997	$1,517.2	10.25%	33%
1996	$1,441.2	11.00%	33%
1995	$1,333.1	12.00%	33%

[1] preliminary

1998–2000 Revenue Requirement Decision

In June 1997, the Utility and other interested parties reached a negotiated settlement to set the revenue requirements for the Utility for the years 1998–2000, which was approved by the BCUC on July 23, 1997.

The key points of the settlement are as follows:

- Cost recovery implicit in the 1998 to 2000 rates requires BC Gas Utility to achieve productivity gains in operating and maintenance costs of 2% in each of 1998 and 1999 and 3% in 2000. Restructuring costs of up to $3 million associated with achieving these productivity targets can be deferred and recovered in customer rates. By implementing the restructuring program and other initiatives, the Utility has taken steps to reach and exceed these productivity targets in each year of the settlement.
- Commencing January 1, 1998, new incentives for demand side management activities and capital expenditure efficiency are available. To the extent that demand side management programs exceed targets, and to the extent that unit costs of certain classes of capital expenditures are lower than the allowed level, the Utility has opportunities to generate earnings incremental to what would be allowed in a conventional regulatory framework. These programs did not have a material impact on earnings in 1998.
- An earnings sharing mechanism is incorporated whereby variances in achieved return on equity from that allowed by the BCUC in a given year are to be shared equally with customers. Earnings from the established incentive programs are not included in the earnings sharing mechanism.
- The ratio of overheads capitalized has been, and will be reduced from 22.5% of gross operating and maintenance costs in 1997 to 20% in 1998 and 1999, and to 16% in 2000.
- The allowed common equity component is to remain at 33% of capitalization, and $150 million of outstanding first preference shares are to be refinanced with long-term debt as they become redeemable in 1999 and 2000.
- Through an annual review process, rates for the upcoming year are adjusted to reflect projected changes in factors such as customer growth, industrial revenues, cost of natural gas, interest rates, and taxes.

In addition to the incentives noted above, the Gas Supply Mitigation Incentive Plan provides an incentive for the Utility to reduce gas supply costs to customers. The benefits to shareholders under this Plan amounted to $2.4 million (pre-tax) in 1998.

Southern Crossing Pipeline Application

BC Gas Utility has filed an application to the BCUC for a Certificate of Public Convenience and Necessity ("CPCN") in regards to the proposed Southern Crossing Pipeline project. The SCP, which is estimated to cost approximately $348 million, includes 312 kilometres of 24-inch (610-mm) pipeline to be constructed from Yahk, B.C. in the southeastern corner of the province to Oliver, B.C. at the south end of the Okanagan valley, as well as related compression facilities. The routing will primarily follow existing pipeline rights-of-way.

MANAGEMENT DISCUSSION AND ANALYSIS

In April 1998, an earlier CPCN application to the BCUC for the Southern Crossing Pipeline project was denied. In its decision, the BCUC noted that BC Hydro would have requirements for natural gas to fuel thermal generation projects and directed BC Gas to examine the feasibility of obtaining peak shaving from BC Hydro and its natural gas-fired electricity suppliers. The BCUC further noted "if there is a requirement for new pipeline infrastructure upstream of Huntingdon to serve these loads, BC Gas may wish to re-examine the SCP and attempt to obtain commitments from BC Hydro for capacity on the SCP which would make it a viable alternative."

In November 1998, BC Gas entered into peak service agreements and transportation agreements with BC Hydro and also concluded transportation and peak shaving agreements with a third party customer. Accordingly, a revised CPCN application for the SCP was filed with the BCUC in December 1998. This application is currently under review by the BCUC. A decision from the BCUC is expected in the spring of 1999.

Business Risks

Regulatory Treatment
BC Gas Utility, through the rate-making process, relies on the BCUC to set rates that will allow the Utility to earn a fair return for its common shareholders. In addition, the BCUC approves the allowable cost of providing service, the capital structure employed to finance the Utility's investment in plant and equipment, and various other aspects of the Utility's operation. Fair regulatory treatment that allows the Utility to earn a risk adjusted rate of return comparable to that available on alternative investments is essential for ongoing success.

In management's view, the successful negotiation and approval of the 1998-2000 Revenue Requirement settlement is another positive step in the evolution of the Utility's regulatory relationship with the BCUC and its customers. The incentives in that settlement, which are subject to renegotiation for the years after 2000, demonstrate that incentive regulatory arrangements have gained the support of the BCUC and customer groups as an approach that can streamline the regulatory process while implementing incentives which benefit, and align the interests of, both customers and shareholders.

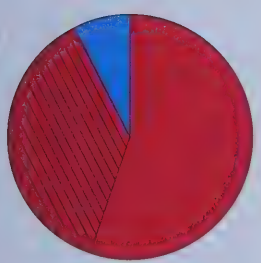
Long-term Competitiveness
As the energy industry in North America continues to experience structural change, it is essential that BC Gas Utility challenge the level of ongoing operating expenses and commitment of capital resources. Management of the Utility has worked with the BCUC to incorporate productivity targets, in the form of decreased operations and maintenance spending per customer of 2%, 2% and 3% for 1998, 1999 and 2000 respectively. In addition, a new capital expenditure efficiency mechanism was incorporated into the 1998–2000 settlement, and policies for mains extensions continue to be refined and improved, thereby reducing the required net investment in each new customer addition.

Future competition in the energy market will introduce new risks to BC Gas Utility. Challenging its own investment criteria, as well as those imposed on its customers from external forces, is an important component of the Utility's strategy for maintaining the long-term competitive position of natural gas as an economic source of energy for British Columbians.

MANAGEMENT DISCUSSION AND ANALYSIS

Petroleum Transportation

1998 Transportation Volumes



Canadian mainline

U.S. mainline (included in Canadian mainline)

Jet fuel deliveries

U.S. pipeline and jet fuel volumes represented 45 per cent of total 1998 transportation volumes.

Customer Additions

New customer additions at BC Gas Utility are typically a result of population growth and new housing starts. In recent years, British Columbia has experienced declining immigration, population growth and housing starts which has resulted in a similar decline in new customer additions for the Utility. BC Gas Utility anticipates that the recent customer addition rates may continue for the next several years. The Utility is working to expand its market for natural gas service by increasing its penetration of the multiple family development market.

Gas Supply

BC Gas continues to face significant physical risk related to gas supply disruption as it is dependent on a limited selection of pipeline and storage providers. This risk is particularly acute in the Vancouver-Lower Mainland service area where the majority of BC Gas Utility's core market customers are located. These customers rely primarily on the transportation services of one pipeline company. In addition, the limited transportation and storage alternatives present risks of both supply disruption and lack of access to competitive sources of natural gas.

To the extent possible, BC Gas Utility has attempted to minimize gas supply and price risk through the use of long-term transportation, storage and supply contracts, hedging instruments and a diverse supply portfolio. In 1998, management has actively pursued several initiatives to allow for the transportation of gas supplies through alternate pipeline infrastructure. Specifically, BC Gas Utility's application before the BCUC for the Southern Crossing Pipeline is intended to address this risk as well as to minimize the delivered cost of gas to the Utility's core customers over the long term.

During the SCP hearing before the BCUC in the Fall of 1997, it became apparent from the evidence of several participants in the hearing that the regional peak day demand in British Columbia and the U.S. Pacific Northwest significantly exceeds the supply available from the existing infrastructure. Management believes that the SCP is an integral factor in meeting the growing demands for natural gas as well as reducing consumer exposure to supply disruptions and related price increases should the region experience either a cold winter or failure in gas producing, storage or pipeline facilities.

In addition, BC Gas is monitoring with interest the Alliance Pipeline project, which will transport natural gas from northern British Columbia to Chicago, as it has the potential to alter the supply of B.C. basin gas available to consumers in British Columbia. The Alliance Pipeline is expected to transport 300 to 500 Mmcf/d, or approximately 15% to 25% of current production levels in northern B.C., away from the province as early as 2000. The effect of projects such as Alliance underscore the need for the BC Gas Utility system to be better connected to the North American gas pipeline grid in order to have competitive access to alternate gas supply sources to ensure reliable supply and reasonable gas supply costs for gas consumers in British Columbia.

PETROLEUM TRANSPORTATION

Contribution to Earnings

In millions of dollars	1998	1997
Gross revenues	**$135.4**	$129.1
Operating expenses		
Operations and maintenance	**47.6**	44.5
Depreciation and amortization	**16.1**	15.8
Property and other taxes	**19.6**	20.0
	83.3	80.3
Operating income	**52.1**	48.8
Financing costs	**15.0**	13.4
Earnings before income taxes and non-controlling interest	**$ 37.1**	$ 35.4

Revenues

Revenues from petroleum transportation operations increased to $135.4 million in 1998 from $129.1 million in 1997 as a result of higher delivery volumes in 1998. Pipeline deliveries averaged 43,420 cubic metres per day (m^3/d) in 1998 compared to 39,802 m^3/d in 1997.

The overall increase in throughput from 1997 levels is primarily a result of an increase in deliveries of light crude oil shipments to export markets due to capacity constraints on alternate trunk pipeline systems. The volumes of crude oil delivered to Washington State refineries and offshore export markets in the first half of 1998 were a continuation of the unusually high levels experienced the previous year.

Expenses

Operating expenses from petroleum transportation operations increased by $3.0 million from $80.3 million in 1997 to $83.3 million in 1998 mainly as a result of an increase in transportation expenses associated with higher delivery volumes. Financing costs increased from $13.4 million to $15.0 million as a result of higher interest rates and debt levels.

Regulation

The Canadian portion of Trans Mountain's crude oil and refined products pipeline system is regulated by the National Energy Board (the "NEB"). The NEB authorizes pipeline construction and establishes tolls and conditions of service. Traditionally, rates have been set through historical cost rate base and rate of return methodology.

In October, 1995, Trans Mountain entered into negotiations with the Canadian Association of Petroleum Producers and the principal shippers on the crude oil and refined products pipeline system. Those negotiations resulted in an agreement which was approved by the NEB. The agreement provides for the determination of Trans Mountain's revenue requirement, and resulting tolls, over a five-year period which started on January 1, 1996. Trans Mountain's revenue requirement is determined with reference to a negotiated 1996 starting point of $106.0 million, which includes a 1996 provision for income taxes of $7.5 million. Each successive year's starting point, net of income taxes, is adjusted to reflect the yearly rate of change of the Consumer Price Index of Canada.

The negotiated settlement allowed Trans Mountain to retain 100% of earnings up to $13.2 million in 1998, after which earnings are shared 50/50 with the shippers in accordance with the efficiency incentive. In addition, Trans Mountain shares with its shippers on a 50/50 basis certain incremental revenues, net of certain allowances, resulting from an excess capacity incentive. In 1998 the total pre-tax revenues to be credited to the shippers under both of these sharing arrangements was $4.0 million. The shippers will receive from Trans Mountain some $0.8 million in 1999 due to higher than forecast volumes shipped in 1998.

The toll charged for the portion of the pipeline located in Washington State falls under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Regulation by FERC is on a complaint basis. There were no complaints in 1998.

Tolls for the jet fuel pipeline system are regulated by the BCUC on a complaint basis. In 1997 Trans Mountain conducted negotiations with the principal shippers on the jet fuel pipeline system. Those negotiations resulted in an agreement to determine the jet fuel pipeline revenue requirement in a manner substantially similar to the agreement currently in place for the crude oil and refined products pipeline. The agreement will operate for a five-year period commencing January 1, 1998.

Petroleum Transportation Earnings Before Income Taxes and Non-Controlling Interest ($ millions)

1998 results reflected higher throughput on the Canadian and U.S. pipeline systems.

MANAGEMENT DISCUSSION AND ANALYSIS

Corridor Pipeline Limited

In July 1998 Trans Mountain and the Company entered into an agreement with Shell Canada Limited ("Shell") and BHP Diamonds Inc. ("BHP") for the construction and operation of the Corridor pipeline system. Corridor Pipeline Limited ("CPL") has been established as a direct subsidiary of the Company to own and operate this system.

The Corridor pipeline system will provide for the pipeline transportation of diluted bitumen produced at Shell's Muskeg River Mine located approximately 70 km north of Fort McMurray, Alberta to a heavy oil upgrader that Shell proposes to construct adjacent to its existing Scotford Refinery near Edmonton, Alberta, a distance of approximately 453 km. A smaller diameter parallel pipeline will transport recovered diluent from the Upgrader to the Mine. CPL also proposes to construct two additional pipelines, each 43 km in length, to provide pipeline transportation between Shell's proposed Scotford Upgrader and the existing trunk pipeline facilities of Trans Mountain and Enbridge in the Edmonton area.

The Corridor pipeline system remains subject to obtaining regulatory approvals from the Alberta Energy and Utilities Board and Alberta Environmental Protection. A public hearing to consider these applications is scheduled to commence March 9, 1999. Construction of the Corridor pipeline system is also subject to a corporate decision by Shell to proceed with the Muskeg River Mine and Scotford Upgrader. Shell has made a long term commitment to transport 31,800 m^3/day of diluted bitumen and 9,500 m^3/day of diluent in the Corridor pipeline system if the projects proceed.

If the project is approved, the Company will build, own and operate the Corridor Pipeline. At any time prior to thirty days after final project approval by Shell, Shell and BHP have an option to take an equity interest of up to 49% in the pipeline.

Business Risks

Trans Mountain has taken all reasonable and prudent steps to minimize its exposure in the case of a catastrophic event or environmental upset. General risks faced by Trans Mountain include the following.

- Revenues may be reduced if expected throughput levels do not materialize in 1999. Under the incentive toll settlement, this risk is mitigated by a mechanism which permits Trans Mountain to carry forward a throughput related revenue shortfall for recovery in the subsequent year. However, there is no assurance that the level of throughput required for recovery of any accumulated shortfall will materialize in a subsequent year. The mitigating measures do not apply with respect to the portion of the pipeline within the United States.
- Refined products can be imported for the B.C. market through marine offloading facilities in the Port of Vancouver or by truck transportation from refineries in Washington State. In 1998, refined products for the B.C. market represented approximately 28% of Trans Mountain's deliveries. This risk may be mitigated by the adjustment mechanism described above.
- The decision by the NEB requiring Trans Mountain to use the taxes payable method rather than the tax allocation method of accounting for income taxes, which will inevitably result in higher tolls as capital cost allowance benefits are expended, is predicated on the assumption that future shippers will still ship under such increased tolls.
- The pipeline industry is currently addressing the issue of negative salvage values and the risk that the cost of abandonment of the plant at the end of its useful life will not be fully recovered in tolls. Until such time as the magnitude of, and the funding mechanism for, the eventual recovery of negative salvage is determined, Trans Mountain, like other Canadian trunk pipeline systems, makes no provision for these amounts.

MANAGEMENT DISCUSSION AND ANALYSIS

- Trans Mountain maintains a comprehensive Line Integrity Program as a preventive measure to mitigate the risk of a pipeline failure or other loss of system integrity. The Program is intended to reduce both the likelihood and severity of the business interruption and/or environmental liability that could result from a loss of line integrity.
- Total crude oil pipeline capacity out of western Canada increased in 1998 with the expansion of the Enbridge (formerly IPL) system. Total production of light and heavy crude oil in Alberta declined in 1998 primarily due to sustained low crude oil prices. Concurrently, there was an increase in the volume of waterborne crude oil available to west coast markets. The combination of these factors tends to reduce the netbacks available to producers from markets served by Trans Mountain's system in relation to the netbacks available from other markets.

OTHER ACTIVITIES

Contribution to Earnings

In millions of dollars	1998	1997
Gross revenues	$ 47.2	$ 39.0
Operating expenses		
Operations and maintenance	24.4	18.9
Depreciation, depletion and amortization	7.1	6.7
Property and other taxes	1.7	1.6
	33.2	27.2
Operating income	14.0	11.8
Financing costs	20.0	17.3
Loss before NW Energy disposition costs, income taxes and non-controlling interest	$ (6.0)	$ (5.5)

Losses from other activities in 1998 were $6.0 million before NW Energy disposition costs, income taxes and non-controlling interest compared with $5.5 million in 1997. Revenues increased to $47.2 million in 1998 from $39.0 million in 1997 as a result of the construction of a water treatment facility in Dartmouth, Nova Scotia and a natural gas distribution system in the United Arab Emirates city of Sharjah. Operating expenses increased by $6.0 million to $33.2 million in 1998 from $27.2 million in 1997 primarily due to scheduled major maintenance expenditures at the NW Energy electricity generating facility and higher development costs. The increase in financing costs was mainly due to borrowings incurred to finance the acquisition of the one-third interest in NW Energy for a full year and the Company's share repurchase program.

Business Risks

The other activities segment is relatively less significant than the Company's two other segments. Businesses in this segment primarily operate in unregulated industries which are, by their nature, more risky than BC Gas' regulated operations. Therefore, earnings contributions from these businesses are less predictable. Management is optimistic, however, that these companies will become important contributors to the future earnings growth of the Company.

NON-CONTROLLING INTEREST

In millions of dollars	1998	1997
Dividends on preference shares	$ 4.7	$ 4.7
Recovery of Part VI.1 tax	(0.1)	–
NW Energy	–	1.1
	$ 4.6	$ 5.8

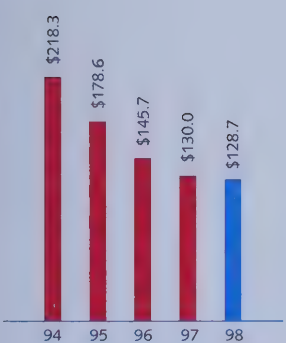
The decrease in the non-controlling interest share of current earnings was primarily due to the acquisition in August 1997 of the remaining one-third interest in NW Energy.

Other Activities Loss before Other Gains & Losses, Income Taxes and Non-Controlling Interest ($ millions)

Higher revenues in 1998 from energy and utility services were offset by higher interest expense associated with borrowings to support the Company's share repurchase program.

MANAGEMENT DISCUSSION AND ANALYSIS

BC Gas Inc.
Consolidated
Capital Expenditures
($ millions)



1998 capital expenditures included the installation of a new business information system.

LIQUIDITY AND CAPITAL RESOURCES

Changes in non-cash operating working capital, offset by an increase in net earnings after adjusting for items not involving cash, resulted in a decrease in cash flow from operating activities to $80.2 million in 1998 from $170.6 million in 1997.

Capital expenditures totalled $128.7 million in 1998 compared with $130.0 million in 1997. The $1.3 million decrease in capital spending was due primarily to lower requirements for mains and services resulting from fewer customer additions compared to 1997, offset by the implementation of a new business information system which will support improved decision making and greater efficiencies.

The capital spending in 1998 is summarized as follows:

In millions of dollars	
Natural gas distribution	
Mains, services and engineering projects	$ 40.5
Land and buildings	3.3
Systems and computer hardware	25.8
Other	11.7
	81.3
Capitalized overhead	29.2
	110.5
Petroleum transportation	16.9
Other activities	1.3
	$128.7

Coverage Ratios

Due to the capital intensive nature of the Company's businesses and the need to raise debt frequently in the fixed income market, maintenance of its financial ratios is a priority for BC Gas. The most significant ratios are considered to be interest coverage and total debt to shareholders' equity. These are presented below on a consolidated basis for the three corporate entities actively issuing debt in the capital markets:

	1998	1997
Interest coverage		
BC Gas	**2.14**	2.13
BC Gas Utility	**2.19**	2.14
Trans Mountain	**3.83**	3.88
Debt to shareholders' equity		
BC Gas	**2.67:1**	2.49:1
BC Gas Utility	**1.59:1**	1.71:1
Trans Mountain	**1.49:1**	1.22:1

Debt Ratings

Securities issued by BC Gas, BC Gas Utility and Trans Mountain are rated by two Canadian bond rating companies, the Dominion Bond Rating Service ("DBRS") and the Canadian Bond Rating Service ("CBRS"). The ratings assigned to securities issued by the BC Gas group of companies are reviewed by DBRS and CBRS on an annual basis. In 1998, CBRS raised its rating on the unsecured long-term debt, 7.10% Preference shares and 6.32% Preference shares of BC Gas Utility from B++, P-3 (High) and P-3 to B++ (High), P-2 (Low) and P-3 (High), respectively. In addition, CBRS changed its Outlook on its ratings of BC Gas Utility unsecured long-term debt from Stable to Positive. The table below summarizes the ratings assigned to the Company's various securities at December 31, 1998.

	DBRS	CBRS
BC Gas Inc.		
Commercial paper	R-1 (Low)	A-1 (Low)
BC Gas Utility		
Commercial paper	R-1 (Low)	A-1
Unsecured debentures	A	B++ (High)
Medium term note debentures and medium term notes	A	B++ (High)
Purchase money mortgages	A	A (Low)
7.10% Preference shares	Pfd-3	P-2 (Low)
6.32% Preference shares	Pfd-3	P-3 (High)
Trans Mountain		
Commercial paper	R-1 (Low)	A-1 (Low)
Unsecured debentures	A (Low)	A (Low)

MANAGEMENT DISCUSSION AND ANALYSIS

Projected Capital Expenditures

BC Gas has estimated total capital expenditures of $145.5 million in 1999 for all of its subsidiaries, which the Company expects to finance with a combination of long-term debt issuance at BC Gas Utility, short-term borrowings and internally generated funds. The breakdown of projected capital expenditures for 1999, excluding capital expenditures for the proposed Southern Crossing Pipeline, is as follows:

In millions of dollars	
Natural gas distribution	
Mains, services and engineering projects	$ 61.7
Land and buildings	2.1
Systems and computer hardware	11.4
Other	11.6
	86.8
Capitalized overhead	29.3
	116.1
Petroleum transportation	29.4
	$145.5

Public Issues

During the year, BC Gas Utility issued $108 million of medium term note debentures at a weighted average interest rate of 5.69%. This compares with $55 million issued in 1997 at an interest rate of 6.20%.

Lines of Credit

The Company has in place lines of credit totalling $675 million to finance cash requirements, comprising $200 million at BC Gas, $350 million at BC Gas Utility and $125 million at Trans Mountain. These lines enable the respective companies to borrow directly from their bankers, issue bankers' acceptances and support commercial paper issued by each company. Bank lines of $195 million were unutilized at the end of 1998. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the Canadian market at rates generally below bank prime.

Common Share Repurchase Program

In July 1996, BC Gas announced a Normal Course Issuer Bid for 2,300,000 common shares of the Company for the period of August 15, 1996 to August 14, 1997. In June 1997, the repurchase program was increased to 4,100,000 shares, and was subsequently extended to August 14, 1998. A total of 3,846,100 common shares were purchased in the open market at an average price of $23.84 per share under this program.

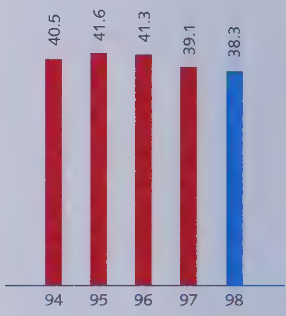
In July 1998, a new share repurchase program was filed which allows the Company to repurchase up to 2,100,000 common shares over the 12-month period ending August 16, 1999. As at December 31, 1998, a total of 86,100 common shares have been purchased in the open market at an average price of $29.04 per share under this new program.

In the year ended December 31, 1998, 857,300 common shares were purchased in the open market at an average purchase price of $29.86 per share, as compared to 2,209,400 shares purchased at an average price of $23.47 per share in 1997.

Dividends

The dividends paid on BC Gas' common shares in 1998 were $1.09 per share, up from $0.975 per share in 1997. In aggregate, BC Gas paid common shareholder dividends of $42.0 million in 1998 compared to $39.1 million in 1997. The increase in the total dollar amount of dividends paid reflects the increased dividend per share, offset by a decrease in the average number of common shares outstanding in 1998 due to the share repurchase program.

BC Gas Inc.
Common Shares Publicly Held at Year End (millions)



Since August 1996, BC Gas has repurchased 3.9 million common shares, representing 8.4 per cent of shares outstanding.

MANAGEMENT DISCUSSION AND ANALYSIS

Financial Instruments and Risk Management

The Company uses financial instruments from time to time to manage its exposure to changes in interest rates where the interest rate risk is not managed through the use of interest rate deferral accounts. These financial instruments are only used for hedging purposes, and are only employed in connection with an underlying asset or liability through counterparties with acceptable credit status. There were no interest rate hedging instruments in place at December 31, 1998.

BC Gas, through its natural gas distribution operations, has undertaken a natural gas price risk management program on behalf of its customers to manage the price volatility of its forecast system gas supply. Part of this program involves the use of financial instruments to effectively fix the price of baseload gas supply.

OTHER MATTERS

Year 2000 Issue

The Year 2000 issue refers to the risk that computers and other devices that rely on microprocessor technology may fail to recognize the Year 2000 if their program logic uses two digits to represent years. BC Gas' business processes and operations rely extensively on computer technology. In addition, the Company relies on third party suppliers to provide products and services, some of which are essential to the operations of BC Gas. A major failure of key company systems or disruption of the delivery of essential products or services as a result of a Year 2000 related problem has the potential to seriously disrupt the business operations of BC Gas.

Recognizing the potential risks involved, BC Gas has completed a company-wide program to assess the potential impact of the Year 2000 issue and system upgrades and conversions are underway. A number of planned initiatives to upgrade the Company's systems have been underway for some time, including a $21 million business information system which was successfully implemented in January 1999. Over and above these capitalized initiatives, expenses for remediation and testing are expected to be between $2 and $3 million, based on current estimates.

The Company expects to complete remediation and testing of its business critical systems by June 30, 1999. Based on the testing done to date on control systems and embedded systems, the Company believes that the Year 2000 issue will not cause disruptions in service. However, the Company cannot be certain that all aspects of the Year 2000 issue affecting the Company, including those aspects relating to the Company's customers, suppliers and other third parties, will be fully resolved. Accordingly, the Company is working closely with major suppliers and customers to identify and rectify potential problems, and is developing contingency plans where possible to deal with failures which could impact its essential services and core operations as a result of the Year 2000 issue.

Disposition of Natural Gas Marketing Contracts

Effective July 1, 1998, the Company's energy marketing subsidiary, Inland Pacific Energy Services Ltd., sold its natural gas contracts for nominal consideration as part of the Company's decision to exit the wholesale trading and commodity function in its non-regulated businesses. BC Gas remains committed to providing industrial energy users with an array of energy-related services through various subsidiaries.

Collective Agreements

Collective agreements with BC Gas Utility employees represented by the Office and Professional Employees International Union (Local 378) and the International Brotherhood of Electrical Workers (Local 213) expired March 31, 1998. Negotiations are continuing.

MANAGEMENT DISCUSSION AND ANALYSIS

OUTLOOK

In 1998, the Company developed a focused business strategy to position BC Gas to capitalize on new opportunities. The Company is taking action to secure and optimize its base businesses, grow from these core businesses into new markets, and position BC Gas to sell new products and services to existing customers.

Although the economy in British Columbia is experiencing slower growth than in previous years, BC Gas Utility's exposure to an economic slowdown is relatively limited, given its mature, diversified customer base and its ability to correct for unanticipated developments in the annual rate resetting process. As a result of the lower economic growth rate, however, customer additions have declined, with a corresponding reduction in rate base growth. The Utility is also addressing the challenge of reductions in the allowed return on equity.

As the largest natural gas distributor in British Columbia, BC Gas Utility is well positioned to thrive in a less regulated and more competitive environment. Competition from non-utility participants in the energy services business as well as from utilities outside the province is increasing as the utility environment becomes less regulated and increasingly focused on delivering choices for customers. Steps have been taken to improve productivity and focus new internal systems on customer requirements. These actions are expected to improve the Company's ability to deliver high quality products and services at a competitive price.

Trans Mountain's delivery volumes will continue to be affected by the relative price competitiveness of Alberta crude oil in the western North American market and by capacity additions on pipelines out of Edmonton. The current low oil price environment will likely result in lower 1999 throughput than the strong levels achieved in 1998. However, as the only petroleum pipeline connecting Alberta with the continent's west coast, Trans Mountain is well positioned to capitalize over the long term on growing demand created by declining Alaska and California crude oil production.

Notwithstanding the shorter term challenges facing BC Gas Utility and Trans Mountain, the Company is committed to sustaining earnings growth. The Southern Crossing and Corridor Pipeline projects, if approved, will create significant shareholder value. In addition, a number of actions have been taken to enhance productivity, renew business processes and refocus the Company to meet customer needs. The Company is well positioned to capitalize on its strategic plan and deliver superior value to shareholders in a competitive energy services market.

MANAGEMENT'S RESPONSIBILITY

The consolidated financial statements have been prepared by management, which is responsible for the integrity and objectivity of this information. These statements have been prepared in conformity with generally accepted accounting principles and, where appropriate, include some amounts that are based on management's best estimates and judgements. The financial information presented elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established systems of internal control which are designed to provide reasonable assurance that assets are safeguarded from loss and that reliable financial records are maintained. These systems are monitored by internal auditors.

KPMG, the auditors appointed by the shareholders, have reviewed the systems of internal control and examined the consolidated financial statements in accordance with generally accepted auditing standards to enable them to express an independent opinion on the financial statements. Their report is set out below.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the financial statements for issuance to the shareholders.

J. M. Reid

John M. Reid
President and Chief Executive Officer

M. Woensdregt

Milton C. Woensdregt
Senior Vice President, Finance
and Chief Financial Officer and Treasurer

Vancouver, Canada
February 2, 1999

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated statements of financial position of BC Gas Inc. as at December 31, 1998 and 1997 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1998 and 1997 and the results of its operations and its cash flows for the years then ended in accordance with generally accepted accounting principles. As required by the Company Act (British Columbia), we report that, in our opinion, these principles have been applied on a consistent basis.

KPMG LLP

Chartered Accountants

Vancouver, Canada
February 2, 1999

CONSOLIDATED STATEMENTS OF EARNINGS

In millions of dollars, except per share amounts *Years ended December 31*	1998	1997
REVENUES		
Natural gas sales and transportation	$ 724.6	$ 743.6
Petroleum transportation and terminalling	134.6	128.5
Electricity sales	32.6	32.3
Other operating revenue *(note 6)*	33.2	29.5
	925.0	933.9
EXPENSES		
Cost of natural gas	338.2	375.2
Operation and maintenance	188.9	184.2
Depreciation and amortization	84.6	77.9
Property and other taxes	52.8	52.6
	664.5	689.9
OPERATING INCOME	260.5	244.0
Financing costs *(note 8)*	121.8	114.7
Other losses *(note 9)*	–	13.7
Restructuring costs	–	9.4
Earnings before income taxes and non-controlling interest	138.7	106.2
Income taxes *(note 10)*		
Current	61.5	56.6
Deferred	1.4	(7.0)
	62.9	49.6
Earnings before non-controlling interest	75.8	56.6
Non-controlling interest *(note 4)*	4.6	5.8
NET EARNINGS	$ 71.2	$ 50.8
Common shares – weighted average (millions)	38.5	40.1
EARNINGS PER COMMON SHARE	$ 1.85	$ 1.27

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

In millions of dollars *Years ended December 31*	1998	1997
Balance, beginning of year	$ 136.1	$ 153.7
Net earnings	71.2	50.8
	207.3	204.5
Dividends on common shares	42.0	39.1
Common shares and share options purchased *(note 5)*	18.7	29.9
Reduction of income taxes related to share issue costs	(0.6)	(0.6)
	60.1	68.4
Balance, end of year	$ 147.2	$ 136.1

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

In millions of dollars *December 31*	1998	1997
ASSETS		
Current assets		
Accounts receivable	$ 166.7	$ 156.4
Inventories of gas in storage and supplies	33.7	26.7
Prepaid expenses	5.0	5.8
Rate stabilization accounts	14.6	–
Income and other taxes receivable	4.9	–
	224.9	188.9
Property, plant and equipment *(note 1)*	2,168.6	2,116.1
Other assets *(note 2)*	72.6	83.1
	$ 2,466.1	$ 2,388.1
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness	$ 5.8	$ 2.5
Short-term notes	474.0	374.0
Accounts payable and accrued liabilities	183.5	164.3
Income and other taxes payable	–	34.7
Rate stabilization accounts	–	24.4
Current portion of long-term debt *(note 3)*	194.8	96.8
	858.1	696.7
Long-term debt *(note 3)*	906.7	993.3
Deferred income taxes	36.3	34.9
Non-controlling interest *(note 4)*	75.0	75.0
	1,876.1	1,799.9
Shareholders' equity		
Capital stock *(note 5)*	363.0	369.7
Contributed surplus *(note 5)*	130.8	133.4
Retained earnings	147.2	136.1
	641.0	639.2
Less cost of common shares held by Trans Mountain	51.0	51.0
	590.0	588.2
	$ 2,466.1	$ 2,388.1

Approved by the Board:

Ronald L. Cliff
Director

John M. Reid
Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions of dollars *Years ended December 31*	1998	1997
Cash flows provided by (used for)		
OPERATING ACTIVITIES		
Net earnings	$ 71.2	$ 50.8
Adjustments for non-cash items		
Depreciation and amortization	84.6	77.9
Deferred income taxes	1.4	(7.0)
Other	(1.1)	–
	156.1	121.7
Changes in non-cash operating working capital	(75.9)	48.9
	80.2	170.6
INVESTING ACTIVITIES		
Property, plant and equipment	(128.7)	(130.0)
Acquisition of remaining interest in NW Energy *(note 9)*	–	(29.0)
Other assets	3.2	8.2
	(125.5)	(150.8)
FINANCING ACTIVITIES		
Increase (decrease) in short-term notes	100.0	(1.9)
Increase in long-term debt	108.3	56.1
Reduction of long-term debt	(96.9)	(10.8)
Issue of common shares	0.5	0.6
Common shares and share options purchased	(28.5)	(55.4)
Dividends on common shares	(42.0)	(39.1)
Other	0.6	(1.2)
	42.0	(51.7)
Net decrease in cash	(3.3)	(31.9)
Cash (bank indebtedness) at beginning of year	(2.5)	29.4
Bank indebtedness at end of year	$ (5.8)	$ (2.5)
Supplemental disclosure of cash flow information		
Financing costs paid in the year	$ 125.0	$ 117.7
Income taxes paid in the year	52.2	23.1

Cash is defined as cash and short-term investments or bank indebtedness.

SIGNIFICANT ACCOUNTING POLICIES

Years ended December 31, 1998 and 1997

The preparation of these consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts in the financial statements and the disclosure of contingent assets and liabilities. A significant area requiring the use of management estimates relates to the determination of useful lives for depreciation and amortization. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiaries. The natural gas distribution operations are conducted through BC Gas Utility Ltd. ("the Utility"). Through Trans Mountain Pipe Line Company Ltd. ("Trans Mountain"), the Company owns and operates a common carrier pipeline system for the transportation of crude and refined petroleum products.

Trans Mountain owns 10.7% (1997 – 10.5%) of the common shares of the Company. The cost of these shares is shown as a deduction from shareholders' equity.

Through Inland Pacific Enterprises Ltd. ("IPEL"), the Company holds interests in various energy and utility related subsidiaries including an interest in NW Energy (Williams Lake) Limited Partnership ("NW Energy"), which owns and operates a wood waste-fired independent electricity generating power plant. On August 5, 1997, IPEL increased its interest in NW Energy from 66.7% to 100%. The acquisition has been accounted for by the purchase method and the results of operations have been included on a wholly-owned basis commencing on the acquisition date.

REGULATION

The Company's natural gas distribution operations are subject to the regulation of the British Columbia Utilities Commission ("the Commission"). The Company's petroleum transportation operations are regulated in Canada by the National Energy Board and, in the United States, tariff matters are regulated by the Federal Energy Regulatory Commission.

These regulatory authorities exercise statutory authority over such matters as rate of return, construction and operation of facilities, accounting practices, and rates and tolls.

INVENTORIES OF GAS IN STORAGE AND SUPPLIES

Inventories of gas in storage and supplies are valued at cost determined mainly on a moving-average basis.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost which includes all direct costs, betterments, an allocation of overhead costs and an allowance for funds used during construction.

Depreciation of regulated assets is provided on a straight-line basis on plant in service at rates approved by regulatory authorities. The cost of depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation.

Depreciation of non-regulated equipment is provided using the declining balance method. Depreciation of the electricity generating power plant is provided over 25 years at a rate that matches the rate at which revenues are recognized pursuant to the Electricity Purchase Agreement (see note 13(a)).

No provision for future removal and site restoration costs has been accrued for regulated operations as the extent of such costs is not currently determinable. Management expects that such costs would be recoverable through future rates or tolls.

DEFERRED CHARGES

The Company defers certain charges which the regulatory authorities require or permit to be recovered through future rates. They are amortized over various periods depending on the nature of the charges and include financing costs such as long-term debt issue costs which are amortized over the original lives of the related debt.

SIGNIFICANT ACCOUNTING POLICIES

Deferred charges not subject to regulation relate to projects which may benefit future periods and will be capitalized on completion or expensed on abandonment of the projects. Amortization is provided on a straight-line basis over periods from 20 to 25 years.

GOODWILL AND INTANGIBLE ASSETS

Goodwill and intangible assets represent the excess of the purchase price over the fair value of the net assets acquired. Goodwill is being amortized over 24.5 years and intangible assets over 20.5 years. Management reviews on an ongoing basis the valuation and amortization of goodwill and intangible assets taking into consideration any events and circumstances which might have impaired the net book value. Goodwill and intangible assets are written down when declines in value are considered to be other than temporary, based upon expected undiscounted cash flows of the entity to which the goodwill and intangible assets relate.

RATE STABILIZATION ACCOUNTS

The Utility is authorized by the Commission to maintain two rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, principally temperature and cost of natural gas fluctuations.

The gas cost reconciliation account ("GCRA") accumulates unforecasted changes in natural gas costs and natural gas cost recoveries. The revenue stabilization adjustment mechanism ("RSAM") accumulates the margin impact of variations in the actual use for residential and commercial customers from forecast use. The balances are amortized as ordered by the Commission.

REVENUES

Revenue from natural gas sales is recorded by the distribution utilities on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the reporting period.

Revenue for the Firm Energy Component from the sale of electricity is recognized as electricity is generated at rates established in the Electricity Purchase Agreement (see note 13(a)).

PENSION PLANS

The cost of pension entitlements earned by employees is determined annually by independent actuaries utilizing the projected benefit method prorated on services. This cost is expensed as services are rendered and reflects management's best estimates of expected plan investment performance, salary growth, future terminations, mortality rates and retirement ages of plan members. Adjustments which result from plan amendments, changes in assumptions and experience gains and losses are amortized over the expected average remaining service life of the employee group covered by the plan.

POST RETIREMENT BENEFITS OTHER THAN PENSIONS

The Company provides certain health care and life insurance benefits to eligible retirees and their dependants. The cost of providing these benefits is expensed as paid which matches the recovery in rates.

INCOME TAXES

The Company's regulated subsidiaries account for income taxes for regulated operations as prescribed by their respective regulatory authorities. This includes following the taxes payable method of accounting for income taxes, accounting for certain assets and the rate stabilization accounts on a net of tax basis and amortizing deferred income taxes as approved by the Commission. Under the taxes payable method, deferred income taxes are not recorded for significant timing differences in reporting revenue and expenses for financial statement purposes and income tax purposes. This method is followed as there is reasonable expectation that all taxes payable in future years will be recoverable from customers at that time.

The Company and its other non-regulated subsidiaries provide for deferred income taxes for all significant timing differences.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Tabular amounts in millions of dollars, except per share amounts
Years ended December 31, 1998 and 1997

1. PROPERTY, PLANT AND EQUIPMENT

1998	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas and petroleum pipeline systems	1% – 10%	$2,284.6	$ 480.7	$1,803.9
Plant, buildings and equipment	1% – 33%	283.7	98.7	185.0
Electricity generating power plant	4.2%	123.2	26.4	96.8
Land and land rights	0% – 5%	84.0	1.1	82.9
		$2,775.5	$ 606.9	$2,168.6

1997	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas and petroleum pipeline systems	1% – 10%	$2,204.6	$ 439.6	$1,765.0
Plant, buildings and equipment	1% – 33%	263.0	96.3	166.7
Electricity generating power plant	4.2%	123.1	21.2	101.9
Land and land rights	0% – 5%	83.5	1.0	82.5
		$2,674.2	$ 558.1	$2,116.1

The composite depreciation rate on regulated assets for the year ended December 31, 1998 is approximately 3.0% (1997 – 3.0%).

Included in property, plant and equipment are assets under capital leases with a cost of $13.0 million (1997 – $20.2 million) and related accumulated depreciation of $6.0 million (1997 – $10.9 million).

2. OTHER ASSETS

	1998	1997
Deferred charges		
Subject to regulation	$ 13.1	$ 23.7
Not subject to regulation	16.0	14.0
	29.1	37.7
Goodwill and intangible assets	39.8	40.2
Long-term receivables and investments	3.7	5.2
	$ 72.6	$ 83.1

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

3. LONG-TERM DEBT

	1998	1997
BC Gas Utility Ltd.		
(a) Purchase Money Mortgages		
11.80% Series A, due September 30, 2000 or September 30, 2015 if extended by holder	$ 75.0	$ 75.0
10.30% Series B, due September 30, 2016	200.0	200.0
(b) Debentures:		
9.75% Series D, due December 17, 2006	20.0	20.0
10.55% Series E, due June 8, 1999; 10.75% to June 8, 2009 if extended by holder	60.0	60.0
8.50% Series F, due August 26, 2002	100.0	100.0
7.25% Series G, due July 28, 1998	–	75.0
8.15% Series H, due July 28, 2003	50.0	50.0
(c) Medium Term Note Debentures and Medium Term Notes:		
8.80% Series 5, due October 14, 1999	55.0	55.0
9.80% Series 6, due February 9, 2005	40.0	40.0
6.20% Series 9, due June 2, 2008	113.0	55.0
5.10% Series 10, due February 2, 2001	50.0	–
Various series, weighted average interest rate of 7.05% (1997 – 7.48%) with maturities ranging from 2001 to 2005 (1997 – 1998 to 2005)	25.0	41.0
(d) Preference Shares:		
7.10% Cumulative Redeemable Retractable First Preference Shares	75.0	75.0
Obligations under capital leases, weighted average interest rate of 6.66% (1997 – 5.73%)	7.0	9.3
	$ 870.0	$ 855.3
Trans Mountain Pipe Line Company Ltd.		
(e) Debentures:		
9.75% Series A, due February 18, 2002	44.9	44.9
10.75% Series B, due November 22, 2004	30.0	30.0
11.50% Series C, due June 20, 2010	35.0	35.0
	109.9	109.9
NW Energy (Williams Lake) Limited Partnership		
(f) 11.39% credit agreement, repayable in blended monthly payments, maturing June 1, 2013	121.5	124.7
Agreements payable, non-interest bearing	0.1	0.2
	121.6	124.9
Total long-term debt	1,101.5	1,090.1
Less current portion of long-term debt	194.8	96.8
	$ 906.7	$ 993.3

(a) Purchase Money Mortgages
The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Utility's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

(b) BC Gas Utility Debentures
The BC Gas Utility debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(c) Medium Term Note Debentures and Medium Term Notes
The Utility's Medium Term Note Debenture Program established in 1993 and renewed in 1995 and 1997 allows for the issuance of up to $400 million aggregate principal amount of debentures during the two year period ending November 26, 1999. Issued debentures are unsecured obligations but are subject to the terms of the Trust Indenture dated November 1, 1977 (see note 3(b)).

(d) Preference Shares
These preference shares are redeemable at the option of the Utility on or after September 30, 1999 and are retractable at the option of the holder on September 30, 1999, at $25 per share plus accrued and unpaid dividends.

(e) Trans Mountain Debentures
The Trans Mountain debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated February 18, 1987, as amended and supplemented.

(f) NW Energy Credit Agreement
The NW Energy credit agreement is secured by a first fixed and specific charge, a floating charge and a security interest over all assets of NW Energy owned and to be acquired, and by a $150 million debenture. The credit agreement contains a number of covenants including maintenance of working capital of NW Energy above $2.1 million and a provision that no distributions be made to partners if the debt service coverage ratio falls below 1.25.

The Utility's Series B Purchase Money Mortgages and Series F and Series H Debentures and Trans Mountain's Series B and Series C Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Assuming the Series A Purchase Money Mortgages and Series E Debentures are not extended by the holders and the 7.1% Preference Shares are redeemed by the Utility or retracted by the holders, required principal repayments over the next five years are as follows:

1999	$194.8
2000	80.2
2001	75.6
2002	151.1
2003	56.8

4. NON-CONTROLLING INTEREST

(a) Non-controlling interest in the consolidated statements of financial position

	1998	1997
6.32% cumulative redeemable first preference shares of the Utility, 3,000,000 shares issued	$ 75.0	$ 75.0

These shares are redeemable at the option of the Utility at $25 per share on or after October 31, 2000, and are exchangeable at the option of the Utility on or after October 31, 2000 for common shares of the Company at a price equal to the greater of $3 and 95% of the weighted average trading price of the common shares at that time.

The shares are exchangeable at the option of the holder on or after January 31, 2001 for common shares of the Company at a price equal to the greater of $3 and 95% of the weighted average trading price of the common shares at that time, subject to the right of the Utility to redeem the shares for cash or to find substitute purchasers for the preference shares.

(b) Non-controlling interest in the consolidated statements of earnings

	1998	1997
Dividends on 6.32% preference shares of the Utility	$ 4.7	$ 4.7
Recovery of Part VI.1 tax	(0.1)	–
NW Energy	–	1.1
	$ 4.6	$ 5.8

5. CAPITAL STOCK

The Company is authorized to issue 750,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

Changes in the issued and outstanding common shares are as follows:

	1998		1997	
	Number	**Amount**	Number	Amount
Outstanding, beginning of year	**43,684,965**	**$ 369.7**	45,857,258	$ 387.8
Issued under:				
Share option plan	**26,090**	**0.4**	29,180	0.4
Payroll deduction employee share purchase plan	**4,118**	**0.1**	7,927	0.2
Shares repurchased	**(857,300)**	**(7.2)**	(2,209,400)	(18.7)
	42,857,873	**$ 363.0**	43,684,965	$ 369.7
Less common shares held by Trans Mountain	**4,592,094**		4,592,094	
Outstanding, end of year	**38,265,779**		39,092,871	

Share Option Plan

The Company has a Share Option Plan whereby officers, directors and certain employees may be granted options to purchase a maximum of 4,000,000 unissued common shares with terms up to 10 years. The option exercise price is the closing sale price of the common shares on the Toronto Stock Exchange on the trading day prior to the date the option is granted. The options are exercisable on a cumulative basis at 20% per annum.

The Plan provides an optionee with the right, by notice in writing, to request the Company to purchase from the optionee for cash all or part of the options as specified in the notice at a price equal to the difference between the market price on the day the notice is received by the Company and the exercise price for those options. Upon receipt of notice requesting the Company to purchase the options from the optionee, the Company has the right to override the request and require the optionee to determine whether or not to exercise the option for unissued common shares. Options purchased by the Company are cancelled. During 1998, options to purchase 379,383 (1997 – 684,310) common shares were purchased for $2.9 million (1997 – $3.5 million), net of income tax benefits of $2.5 million (1997 – $3.0 million), which has been charged to retained earnings.

The outstanding options for common shares at December 31, 1998 are as follows:

Year granted	Common shares	Exercise prices	Expiry year
1990	7,250	14.250	2000
1991	39,477	15.750	2001
1992	43,980	16.375	2002
1993	142,480	14.875	2003
1994	126,280	14.125	2004
1995	335,918	13.875 – 15.375	2005
1996	20,760	15.000 – 18.000	2006
1997	188,500	21.200 – 26.650	2007
1998	136,500	27.500 – 31.850	2008
	1,041,145		

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Shares Repurchased

In July 1996, the Company approved a normal course issuer bid to repurchase up to 2,300,000 of the Company's common shares at market prices from shareholders that accept the bid over a period of up to 12 months between August 15, 1996 and August 14, 1997. In June 1997, the bid was amended so that up to 4,100,000 common shares can be repurchased, and the expiry date was subsequently extended to August 14, 1998.

In July 1998, a new share repurchase program was filed which allows the Company to repurchase up to 2,100,000 common shares over the 12 month period ending August 16, 1999.

During 1998, 857,300 common shares were repurchased for $25.6 million (1997 – 2,209,400 shares for $51.9 million). In accordance with generally accepted accounting principles, capital stock was reduced by $7.2 million (1997 – $18.7 million), contributed surplus by $2.6 million (1997 – $6.8 million), and retained earnings by $15.8 million (1997 – $26.4 million).

Reserved for Issue

At December 31, 1998, the number of common shares reserved for issue to meet rights outstanding is as follows:

Under exchange indenture for 6.32% preference shares of the Utility	5,500,000
Under share option plan	2,592,083
Under dividend reinvestment and share purchase plan	2,062,576
Under payroll deduction employee share purchase plan	421,665
	10,576,324

6. OTHER OPERATING REVENUE

	1998	1997
Other natural gas distribution revenue	$ 16.8	$ 21.4
Gas marketing and international consulting revenue	11.2	6.0
Allowance for equity funds used during construction	1.1	0.9
Retail energy services and other	4.1	1.2
	$ 33.2	$ 29.5

7. PENSION PLANS

The Company has defined benefit pension plans available for employees. As at December 31, 1998, actuarial projections of employees' compensation levels to the time of retirement indicate that the present value of accrued pension benefits is $173.0 million (1997 – $161.1 million), and the market related value of the assets available to provide these benefits is $179.3 million (1997 – $164.5 million).

8. FINANCING COSTS

	1998	1997
Interest and expense on long-term debt	$ 99.0	$ 96.4
Other interest	18.6	13.9
Interest capitalized	(1.1)	(0.9)
	116.5	109.4
Dividends on 7.1% preference shares of the Utility	5.3	5.3
	$ 121.8	$ 114.7

9. OTHER LOSSES

On August 5, 1997, the Company increased its interest in NW Energy from 66.7% to 100% for cash consideration of $29 million, which was allocated primarily to intangible assets. In 1997, subsequent to the acquisition, the Company wrote off $13.7 million ($9.3 million or $0.23 per share after tax) of costs incurred in anticipation of the disposition of its interest in NW Energy.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. INCOME TAXES

(a) Variation in Effective Income Tax Rate

Consolidated income taxes vary from the amount that would be computed by applying the federal and British Columbia combined statutory income tax rate of 45.62% to earnings before income taxes and non-controlling interest as shown in the following table:

	1998	1997
Earnings before income taxes and non-controlling interest	$ 138.7	$ 106.2
Combined statutory income taxes in the Province of British Columbia	$ 63.3	$ 48.4
Add *(deduct)* tax effect of:		
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	(9.0)	(7.2)
Large Corporations Tax	4.8	4.3
Losses carried forward	1.7	2.1
Permanent differences between accounting and taxable income	1.6	5.2
Amortization of deferred income taxes	–	(2.7)
Other	0.5	(0.5)
Actual consolidated income taxes	$ 62.9	$ 49.6

(b) Deferred Income Taxes

Accumulated deferred income taxes which have not been recorded in the accounts amount to $215 million at December 31, 1998 (1997 – $206 million).

(c) Income Tax Losses Carried Forward

The Company has non-capital losses carried forward for income tax purposes of $32.4 million at December 31, 1998 (1997 – $22.7 million) which are available to reduce taxable income for years up to 2005. Tax benefits on $12.7 million of such losses carried forward (1997 – $9.8 million) have not been recorded and will be included in the determination of net earnings and earnings per share in the year in which the losses are utilized.

11. FINANCIAL INSTRUMENTS

(a) Fair Value of Financial Instruments

The carrying value of accounts receivable, bank indebtedness, short-term notes and accounts payable and accrued liabilities approximates their fair value due to the relatively short period to maturity of the instruments.

The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 1998, or by using available quoted market prices, is estimated at $1,378.3 million (1997 – $1,347.5 million). The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgement.

(b) Derivative Instruments

The Company uses derivative instruments to hedge its exposures to fluctuations in energy prices, interest rates and foreign currency exchange rates. These instruments are for terms of less than one year.

Natural gas derivatives are used to manage natural gas price risk in the natural gas distribution operations. The majority of the natural gas supply contracts of the natural gas distribution operations have floating prices for natural gas, rather than fixed prices. On behalf of customers, the Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas used for rate making purposes are managed through the regulatory process whereby differences are recorded in a deferral account and passed through to customers in future rates.

Within the natural gas distribution operations, interest rate and foreign currency risk is managed mainly through the regulatory process. As at December 31, 1998, $190 million of short-term borrowings in the natural gas distribution operations were subject to interest rate deferral accounts. Foreign currency risk in the natural gas distribution operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through the regulatory process.

Short-term borrowings in the petroleum transportation and other activities segments are exposed to interest rate risk. The only material foreign currency risk in those business segments relates to the U.S. portion of Trans Mountain's crude oil pipeline system. The petroleum transportation and other activities segments manage interest rate and foreign currency exposures through the use of interest rate and foreign currency derivatives.

The following table provides fair value information on the Company's natural gas and interest rate derivative instruments. The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

	1998		1997	
	Asset (liability)		Asset (liability)	
	Carrying value	Fair value	Carrying value	Fair value
Natural gas derivatives	$ (4.7)	$ (4.6)	$ (5.4)	$ (10.6)
Interest rates derivatives	–	–	(0.2)	(0.3)

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Because it deals with high credit quality institutions in accordance with its established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

12. SEGMENT DISCLOSURES

The Company operates principally in two business segments:

(a) Natural gas distribution, primarily involving the transmission and distribution of natural gas for residential, commercial and large industrial customers in British Columbia; and

(b) Petroleum transportation, primarily involving the transportation of crude and refined petroleum products principally for seven major shippers from Alberta to the west coast of British Columbia and Washington State.

The Company has other activities which include non-regulated energy and utility services as well as corporate interest and administration charges. The non-regulated services include independent power production, international consulting, development of water related infrastructure projects and retail energy services. Also, the Company operates in the United States. At the present time, these operations are not of sufficient size to be reportable as operating or geographic segments.

1998

	Natural gas distribution	Petroleum transportation	Other activities	Total
Revenues	$742.4	$135.4	$47.2	$925.0
Depreciation and amortization	61.4	16.1	7.1	84.6
Operating income	194.4	52.1	14.0	260.5
Financing costs	86.8	15.0	20.0	121.8
Income tax expense (recovery)	51.1	14.2	(2.4)	62.9
Net earnings (loss)	51.8	22.9	(3.5)	71.2
Earnings (loss) per common share	1.35	0.59	(0.09)	1.85
Total assets	1,945.5	356.5	164.1	2,466.1
Capital expenditures	110.5	16.9	1.3	128.7

1997

	Natural gas distribution	Petroleum transportation	Other activities	Total
Revenues	$765.8	$129.1	$39.0	$933.9
Depreciation and amortization	55.4	15.8	6.7	77.9
Operating income	183.4	48.8	11.8	244.0
Financing costs	84.0	13.4	17.3	114.7
Other losses	–	–	13.7	13.7
Restructuring costs	9.4	–	–	9.4
Income tax expense (recovery)	40.2	15.0	(5.6)	49.6
Net earnings (loss)	45.1	20.4	(14.7)	50.8
Earnings (loss) per common share	1.12	0.51	(0.36)	1.27
Total assets	1,862.8	362.6	162.7	2,388.1
Capital expenditures	105.4	23.6	1.0	130.0

13. COMMITMENTS

(a) NW Energy entered into an Electricity Purchase Agreement to supply a certain amount of electricity to BC Hydro for a term of 25 years commencing on April 2, 1993. The price to be paid by BC Hydro consists of a monthly Firm Energy Component and other monthly components to recover certain operating costs subject to certain maximum amounts which are adjusted for inflation.

BC Hydro has a continuing buyout option to purchase the electricity generating power plant during the term of the agreement at the greater of (i) the fair market value of the plant or (ii) the net present value of the Firm Energy Component which would otherwise be payable over the term of the agreement discounted at 12.54% plus the cost of transferring title of the plant to BC Hydro. In the event BC Hydro exercises its option, an amount which approximates the fair market value of the long-term debt as stipulated in the NW Energy credit agreement plus any accrued or unpaid interest is repayable to the lenders in the event of the sale of the plant.

(b) The Utility and Trans Mountain have entered into operating leases in respect of their head office and other premises. Minimum payments under these leases are approximately $6.3 million in each of the next four years and $31.7 million in aggregate.

14. UNCERTAINTY DUE TO THE YEAR 2000 ISSUE

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000, and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect the Company's ability to conduct normal business operations. The Company has completed an enterprise-wide program to assess the potential impact of the Year 2000 Issue and system upgrades and conversions are underway. The Company is working closely with major suppliers and customers to identify and rectify potential problems. However, it is not possible to be certain that all aspects of the Year 2000 Issue affecting the Company, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

SELECTED CONSOLIDATED FINANCIAL STATEMENT INFORMATION – UNAUDITED

Dollar amounts in millions *Years ended December 31*	1998	1997	1996	1995	1994
Statements of Earnings					
Operating revenue	$ 925.0	$ 933.9	$ 901.4	$ 894.9	$ 854.0
Operating expenses	664.5	689.9	670.1	693.9	695.2
Operating income	260.5	244.0	231.3	201.0	158.8
Other expenses	121.8	137.8	89.7	128.2	109.4
Income taxes	62.9	49.6	32.1	22.6	6.0
Non-controlling interest	4.6	5.8	3.9	2.7	7.4
Net earnings	$ 71.2	$ 50.8	$ 105.6	$ 47.5	$ 36.0
Assets					
Current assets	$ 224.9	$ 188.9	$ 305.2	$ 234.6	$ 203.9
Property, plant and equipment (net)	2,168.6	2,116.1	2,062.6	2,056.8	1,948.4
Other assets	72.6	83.1	59.3	75.9	72.3
Total assets	$2,466.1	$2,388.1	$2,427.1	$2,367.3	$2,224.6
Liabilities and Shareholders' Equity					
Current liabilities	$ 858.1	$ 696.7	$ 648.2	$ 673.4	$ 598.9
Long-term debt	906.7	993.3	1,033.9	1,003.9	986.5
Other liabilities	111.3	109.9	114.3	120.1	95.2
Shareholders' equity	590.0	588.2	630.7	569.9	544.0
Total liabilities and shareholders' equity	$2,466.1	$2,388.1	$2,427.1	$2,367.3	$2,224.6
Cash Flow Data					
Operating cash flow	$ 80.2	$ 170.6	$ 166.8	$ 106.7	$ 110.9
Capital expenditures	$ 128.7	$ 130.0	$ 145.7	$ 178.6	$ 218.3

SELECTED OPERATING STATISTICS – UNAUDITED

Dollar amounts in millions *Years ended December 31*	1998	1997	1996	1995	1994
Natural Gas Distribution Operations					
Revenues					
Residential	**$ 423.1**	$ 431.1	$ 405.5	$ 405.3	$ 385.4
Commercial	**226.3**	246.9	231.3	241.6	230.2
Small industrial	**22.5**	17.3	14.7	14.5	10.8
Large industrial and other	**19.1**	19.7	19.4	25.9	39.6
Total natural gas sales revenue	**$ 691.0**	$ 715.0	$ 670.9	$ 687.3	$ 666.0
Transportation	**33.6**	28.6	33.9	28.1	23.1
Other	**17.8**	22.2	19.5	20.1	18.9
Total natural gas revenue	**$ 742.4**	$ 765.8	$ 724.3	$ 735.5	$ 708.0
Natural gas volumes *(billion cubic feet)*					
Sales volumes	**117.1**	123.0	129.5	119.4	122.3
Transportation volumes	**52.1**	52.0	53.0	50.8	46.2
Total natural gas volumes	**169.2**	175.0	182.5	170.2	168.5
Customers at year end	**742,305**	732,316	716,421	699,012	680,970
Petroleum Transportation Operations					
Revenues	**$ 135.4**	$ 129.1	$ 132.8	$ 114.0	$ 105.9
Transportation volumes *(m^3/day)*					
Canadian mainline	**40,160**	36,523	39,681	35,554	34,341
Jet fuel deliveries	**3,260**	3,279	3,358	2,841	2,514
Total throughput	**43,420**	39,802	43,039	38,395	36,855
U.S. mainline *(included in Canadian mainline)*	**16,128**	15,004	16,294	13,293	11,477
Kilometres of pipelines					
Natural gas distribution operations	**36,473**	35,971	35,335	34,401	32,993
Petroleum transportation operations	**1,477**	1,477	1,477	1,477	1,477
Employees *(consolidated)*	**1,819**	1,979	1,965	1,979	1,996

SELECTED CONSOLIDATED FINANCIAL STATISTICS – UNAUDITED

In millions, except where stated otherwise	1998	1997	1996	1995	1994
Return on average shareholders' equity	**12.1%**	10.7%	10.3%	8.6%	7.2%
Dividend payout ratio	**0.59**	0.77	0.36	0.77	0.96
Interest coverage ratio	**2.14**	2.13	1.83	1.57	1.45
Debt/debt plus shareholders' equity	**0.73**	0.71	0.69	0.72	0.72
Common shares outstanding – weighted average	**38.5**	40.1	41.8	41.0	38.7
Data Per Common Share					
Earnings before non-recurring items	**$ 1.85**	$ 1.63	$ 1.48	$ 1.18	$ 0.93
Earnings after non-recurring items	**$ 1.85**	$ 1.27	$ 2.53	$ 1.16	$ 0.93
Dividends	**$ 1.09**	$0.975	$0.900	$0.900	$0.900
Operating cash flow	**$ 2.08**	$ 4.25	$ 3.99	$ 2.60	$ 2.87
Equity	**$15.42**	$15.05	$15.28	$13.70	$13.44
Market price range – High	**$34.00**	$28.00	$21.15	$16.00	$17.25
– Low	**$25.50**	$20.10	$15.00	$13.13	$13.13
– Close	**$30.50**	$27.80	$20.30	$16.00	$13.50

SELECTED QUARTERLY FINANCIAL DATA – UNAUDITED

In millions, except where stated otherwise	Three months ended				Year ended
1998	March	June	September	December	December
Revenues	$313.2	$183.3	$137.4	$291.1	$925.0
Net earnings (loss)	$ 51.9	$ (1.5)	$ (13.6)	$ 34.4	$ 71.2
Data per common share					
Earnings (loss)	$ 1.33	$ (0.03)	$ (0.35)	$ 0.90	$ 1.85
Dividends paid	$ 0.25	$ 0.28	$ 0.28	$ 0.28	$ 1.09
Common share trading – TSE					
High	$31.65	$33.90	$34.00	$32.75	$34.00
Low	$25.50	$29.90	$28.00	$28.25	$25.50
Close	$30.30	$31.85	$28.85	$30.50	$30.50
Volume	4.0	3.0	6.8	2.2	16.0
Common shares outstanding – weighted average	38.9	38.7	38.6	38.5	38.5

1997					
Revenues	$342.9	$168.1	$125.9	$297.0	$933.9
Net earnings (loss)	$ 69.5	$ (17.9)	$ (25.1)	$ 24.3	$ 50.8
Data per common share					
Earnings (loss)	$ 1.69	$ (0.42)	$ (0.61)	$ 0.61	$ 1.27
Dividends paid	$0.225	$0.250	$0.250	$0.250	$ 0.975
Common share trading - TSE					
High	$22.20	$26.30	$27.60	$28.00	$28.00
Low	$20.25	$20.10	$23.00	$24.00	$20.10
Close	$21.25	$26.00	$25.05	$27.80	$27.80
Volume	2.1	4.0	3.7	1.9	11.7
Common shares outstanding – weighted average	41.1	40.7	40.4	40.1	40.1

BOARD OF DIRECTORS

L.I. (Larry) Bell
West Vancouver, British Columbia
President and Chief Executive Officer, Shato Holdings Ltd.

Robert G. Brodie
Barbados
Chairman, Townsite Apartments Ltd.

Thomas A. Buell
Delta, British Columbia
Corporate Director

Brian A. Canfield
Point Roberts, Washington, U.S.A.
Chairman, BCT.TELUS Communications Inc.

Donald A. Carlson
Edmonton, Alberta
President, Carlson Development Corporation Ltd.

Marilyn E. Cassady
Vancouver, British Columbia
Corporate Director

Ronald L. Cliff, C.M., FCA
West Vancouver, British Columbia
Chairman, BC Gas Inc.

Mark L. Cullen
Vancouver, British Columbia
President, Mark Cullen & Company Ltd.

Iain J. Harris
Vancouver, British Columbia
Chairman and Chief Executive Officer, Summit Holdings Ltd.

Robert E. Kadlec
West Vancouver, British Columbia
Chairman and Chief Executive Officer, Bentley Capital Corp.

C. Francis Murphy
Vancouver, British Columbia
Counsel, Farris, Vaughan, Wills and Murphy

John M. Reid
Vancouver, British Columbia
President and Chief Executive Officer, BC Gas Inc.

Robert T. Stewart
West Vancouver, British Columbia
President, R.T. Stewart & Associates

David W. Strangway
Vancouver, British Columbia
President, Canada Foundation for Innovation

BC Gas Inc. directors are also directors of BC Gas Utility Ltd. and Trans Mountain Pipe Line Company Ltd.

COMMITTEES OF THE BOARD

Executive Committee

R.L. Cliff (Chair),
I.J. Harris, J.M. Reid and R.T. Stewart

Exercises all the powers of the Directors (except for certain significant decisions reserved by the Board of Directors) in overseeing the management and direction of the Company during intervals between Board meetings.

Audit Committee

T.A. Buell (Chair),
B.A. Canfield, M.L. Cullen,
I.J. Harris and R.E. Kadlec

Acts on behalf of the Board in reviewing certain financial information prepared for public distribution and in monitoring internal accounting controls. The Committee is responsible for assuring that the Company's financial statements accurately portray the financial condition of the Company and for providing reasonable assurances that the Company is in compliance with applicable laws and regulations, is conducting its affairs ethically and maintains effective controls. The Committee also recommends the appointment, change or reappointment of auditors.

Corporate Governance Committee

R.T. Stewart (Chair)
R.G. Brodie, T.A. Buell, C.F. Murphy and D.W. Strangway

Ensures that an effective and efficient approach to corporate governance is developed and implemented, with the objective of assuring the business and affairs of the Company are carried out in a manner that will enhance shareholder value. In consultation with the Chairman of the Board, the Committee is responsible for identifying, evaluating and recommending nominees for the Board of Directors.

Environment and Safety Committee

M.E. Cassady (Chair),
L.I. Bell, D.A. Carlson and
I.J. Harris

Reviews and approves corporate environmental policy, evaluates the Company's progress in implementing the policy, reviews relevant data and reports, brings information and recommendations to the attention of the Board as appropriate.

Management Resources Committee

L.I. Bell (Chair),
B.A. Canfield, R.L. Cliff and
R.E. Kadlec

Ensures the Company has a plan for continuity of its officers and an executive compensation plan that is motivational and competitive in order to attract, hold and inspire the performance of Executive Management and other key personnel. The intent of the Committee is to enhance the profitability and growth of the Company through effective succession planning.

OFFICERS

BC GAS INC.

Ronald L. Cliff, C.M., FCA
Chairman of the Board

John M. Reid
President and Chief Executive Officer

Gordon R. Barefoot
Senior Vice President, Planning and Development

Milton C. Woensdregt
Senior Vice President, Finance, and Chief Financial Officer, and Treasurer

Donald C. Fairbairn
Vice President, Business Development

David M. Masuhara
Vice President and Secretary

Debra G. Nelson
Assistant Corporate Secretary

BC GAS UTILITY LTD.

Ronald L. Cliff, C.M., FCA
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Assistant Corporate Secretary

TRANS MOUNTAIN PIPE LINE COMPANY LTD.

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Vice President, Financial Services and Regulatory Affairs

Milton C. Woensdregt
Treasurer

Michael W.P. Boyle
Corporate Solicitor and Assistant Secretary

Chuck K. Sam
Controller and Assistant Treasurer

INVESTOR INFORMATION

ANNUAL GENERAL MEETING

The Annual General Meeting of Shareholders will be held at 11:00 a.m. on Wednesday, April 28, 1999 in the Park Ballroom of the Four Seasons Hotel in Vancouver, British Columbia.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Registered holders of the Company's Common shares (except residents of the United States) may elect to reinvest their cash dividends in new Common shares. Participants in the Plan may also make optional cash payments of up to $20,000 per calendar year to purchase additional Common shares. Optional cash payments must be received by the Registrar and Transfer Agent by the last days of January, April, July and October to be reinvested on the following dividend payment date. There are no brokerage commissions payable on shares purchased pursuant to the Plan. For an information package on the Plan, or to register in the Plan, please contact Shareholder Relations.

EMPLOYEE SHARE PURCHASE PLAN

Employees of BC Gas Utility Ltd. may contribute from 2% to 6% of their earnings through payroll deductions to purchase the Company's Common shares. Shares are purchased at 100% of the market price.

COMMON SHARE DISTRIBUTION

Approximately 99% of the outstanding Common shares are owned by residents of Canada. The following table summarizes the distribution of shares at December 31, 1998.

	Shareholders	*Shares*
Canada	7,705	42,525,895
USA	114	291,135
Others	31	40,843
Total	7,850	42,857,873

COMMON SHARE OWNERSHIP CONSTRAINTS

In accordance with the statute that privatized the Company, the following constraints on BC Gas Inc. share ownership exist: (i) the total number of voting shares held by any one person or associated persons shall not exceed 10% of the total number of issued and outstanding voting shares; and (ii) non-residents of Canada will not be permitted to hold or beneficially own in the aggregate, directly or indirectly, voting shares to which are attached more than 20% of the total number of voting shares outstanding.

Valuation Day Value (December 22, 1971)
Common Shares [1]$6.50
February 22, 1994 Closing Price, $15.50

[1]Adjusted for the two-for-one stock split on November 18, 1985.

REGISTRAR AND TRANSFER AGENT

Shareholder accounts, including dividend payments, direct deposit service and the transfer of shares are handled by the Company's registrar and transfer agent:

CIBC Mellon Trust Company
Mall Level, 1177 West Hastings Street
Vancouver, B.C. V6E 2K3
Telephone: (604) 688-4330
Toll Free: 1-800-387-0825

DUPLICATE ANNUAL AND INTERIM REPORTS

To eliminate duplicate mailings of annual and quarterly reports, please contact CIBC Mellon Trust Company.

SHARES LISTED (Symbol: BCG)

The Toronto Stock Exchange
Montreal Exchange
Vancouver Stock Exchange

SCHEDULED DIVIDEND PAYMENT DATES

February 28, 1999
May 31, 1999
August 31, 1999
November 30, 1999

CORPORATE OFFICES

BC Gas Inc. and BC Gas Utility Ltd.
1111 West Georgia Street
Vancouver, B.C. V6E 4M4
Main Telephone: (604) 443-6500

Trans Mountain Pipe Line Company Ltd.
Suite 900 – 1333 West Broadway
Vancouver, B.C. V6H 4C2
Telephone: (604) 739-5000

Inland Pacific Enterprises Ltd.
Suite 1600 – 1095 West Pender Street
Vancouver, B.C. V6E 2M6
Telephone: (604) 895-3500

SHAREHOLDER RELATIONS

Inquiries regarding the Company's Dividend Reinvestment and Share Purchase Plan and all other inquiries or comments by shareholders regarding the Company should be directed to:

Debra Nelson
Telephone: (604) 443-6559
Toll Free: 1-800-667-9177
Fax: (604) 443-6904
e-mail: shareholder@bcgas.com

INVESTOR RELATIONS

Portfolio managers, investment analysts and other investors requesting financial information regarding BC Gas should contact:

David Bryson
Telephone: (604) 443-6527
Fax: (604) 443-6929
e-mail: ir@bcgas.com

INTERNET

Website: www.bcgas.com

Glossary

Bitumen A hydrocarbon liquid of high density and viscosity. In Alberta, it is usually associated with oilsands deposits and when extracted it is too viscous to be transported by pipeline at normal ambient conditions.

British Columbia Utilities Commission A provincially appointed body that regulates the potential earnings, business operations and practices of several B.C. utilities.

Btu British thermal unit. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

Core Market Generally refers to non-industrial and non-utility purchasers of natural gas and includes residential, commercial and institutional (i.e.: hospitals, universities) purchasers of natural gas.

Demand Charge The portion of the cost of transportation that is payable on the full contracted capacity regardless of whether or not the space is used.

Demand Side Management (DSM) Utility programs designed to influence the customer's energy consumption. Such programs include reducing gas consumption through efficiency and conservation, load shaping programs to reduce peak load and/or increase off peak load, and programs to encourage fuel substitution.

Diluent A hydrocarbon liquid of low density and viscosity. It is usually blended with raw bitumen to create a fluid which can be transported by pipeline at normal ambient conditions.

Fixed Price Contracts Contractual requirements for the purchase of a minimum quantity of gas whether or not delivery is accepted by the purchaser.

Gigajoule (GJ) 0.95 thousand cubic feet of natural gas at 1000 Btu per cubic foot or 0.28 megawatt hours of electricity. Terajoule (TJ) is one thousand gigajoules and petajoule (PJ) is one million gigajoules.

Interruptible Customers Gas customers who choose low priority service, usually at lower rates under schedules or contracts that anticipate and permit interruption of gas service on short notice, generally in peak load seasons.

Intervenor An active participant in a hearing, typically representing one or a group of customers.

National Energy Board A federal regulatory body that oversees interprovincial and international oil and gas pipelines, as well as the export and import of electricity, oil and gas.

Peak Shaving The process of supplying gas to a utility system from an auxiliary source, such as storage or liquefied natural gas, during periods of maximum demand to reduce the load or demand on the primary source of supply, usually a pipeline.

Rate Base The investment in gas plant in service and working capital on which utilities earn a rate of return to compensate shareholders and holders of the utility debt.

Revenue Requirement The total revenues to be generated by rates in order to recover the costs of providing service.

Shippers Entities holding transportation contracts on pipelines which require payment of tolls.

TCF Trillion (10^{12}) cubic feet of natural gas.

Tolls The rates charged by pipeline companies under tariffs approved by regulatory bodies for such services as raw gas transmission, processing and transportation.

Transportation A gas delivery service provided by a pipeline or local gas utility company to customers who purchase natural gas directly from producers or brokerage companies.

Metric To Imperial Conversions

1 GJ =	0.9482 MMBtu
1 10^3m^3 =	35.301 MCF
1 m^3 =	6.290 Barrels
1 km =	0.6214 miles

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BC Gas Inc.

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